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NRC·CNRC Energy Storage for Grid Security and Modernization

Canadian Energy Storage Report:
2017 Case Study for the Alberta Market

Prepared by:

Chaouki Regoui, Ryan Baker, Giovanna Gonzales-Calienes, Steven Shi, Yuri Grinberg, Miyuru Kannangara, Kourosh Malek, Qianpu Wang, Farid Bensebaa, Adam Tuck, Will Skrivan

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Note that this report reflects the beliefs and opinions of the NRC authors based on best available information at the time of writing. This report does not necessarily represent the views of the advisory board members, their affiliated organization, or any other stakeholder groups.

Preface

Added August 30, 2019

Since the time the analyses described in this Alberta Chapter study were performed, significant changes to energy policy and environmental regulations in Alberta have been implemented. Some of the specific changes in policies/regulations and their anticipated impacts on the inputs and results of these analyses are listed in the table below.

Policy	Key Change Since Time of This Analysis	Estimated Impacts of Change to Analysis Results
Renewable Electricity Program (REP)	Announcement that there are no future rounds of REP[1]	The report assumptions are based on future rounds of REP which are no longer planned. Without the REP, there would be less incentive to develop renewable generation in the Alberta grid. In terms of the impacts for this analysis, removing the REP increases the uncertainty in the future state of the grid used in Pillar 1's model. However, in the longer term, for example 2027 and beyond, the technology cost of ES is expected to decrease. It is anticipated that some ES projects would be able to compete with a conventional generation fleet in Alberta as they offer grid stability and resilience benefits that conventional generation cannot. In Pillar 2, individual ES systems were modelled first in Use Cases or Grid Service Bundles without, and then with, a Capacity Market. Also, those Use Cases were repeated in a sub scenario without, and then with, Transmission Deferral. Transmission Deferral is an option to deal with capacity additions in the AESO 2017 LTO to transmission-constrained regions. So at the project or individual ES level in Pillar 2, the presence / absence of the REP doesn't affect the simulation results with or without a Capacity Market. Also unchanged are the Transmission Deferral sub scenario's result trends related to markets / services opportunity cost and long vs short duration ES. However, the exact impact on the discrete results of the Transmission Deferral sub scenario is unknown.

[1] https://www.aeso.ca/market/renewable-electricity-program/

Capacity Market	Announcement on July 24, 2019 that the energy-only market will continue and there will not be a transition to a capacity market[2]	At the time of the study, a capacity market in Alberta was being evaluated and designed. In Pillar 1's model, the effects of capacity market were referenced from other jurisdictions in North America where a capacity market was in effect. As a capacity market offers a potential additional revenue stream for qualifying ES projects, the continuation of the energy-only market could decrease *the number of potential ES projects* by 20% in Alberta over our study period[3]. In the Pillar 2 analysis, comparing all ES NPV's with and without a Capacity Market, NPV decreases on average 24% (+/- 10%). Although a Capacity Market increased NPV for all ES modelled in Pillar 2, it didn't change whether or not that NPV was a profit or a loss. Therefore, revenue from a Capacity Market was significant, but wasn't an "anchor service". Financial results without and with a Capacity Market are shown in Tables 2-17 and 2-18, and in Figures 2-2 to 2-4.
Carbon Tax	Repealed on May 30, 2019[4]	In Pillar 1's model, the carbon tax impacts the generation mix of the model. As part of the Alberta Carbon Tax, the Carbon Levy was officially repealed on May 30, 2019. This reduced the fuel cost of conventional thermal-based generation in Alberta. This policy change was evaluated in this analysis in the +/- 40% fuel cost scenarios. The CCIR is still in effect in Alberta, and therefore adds constraints to conventional thermal-based generation to be developed in the future. The CCIR is mapped to the "Carbon Tax" parameter in our study model and assumed to have a value of $30 per metric tonne.

[2] https://www.aeso.ca/market/capacity-market-update/

[3] The potential 20% decrease in the number of potential ES projects is based on the information collected for this study regarding the preliminary design of the planned Capacity Market framework for Alberta. It assumes that only an energy storage system with a minimum 4-hour duration will be qualified to participate in the then planned Capacity Market. For the 105 potential ES projects of the pillar 1's output, only 25 of the long-duration potential ES projects (see Appendix 6.1) qualify to participate in the planned Capacity Market. The continuation of energy-only market will reduce the revenue stream for those potential projects, but may or may not impact the deployment of the potential project.

[4] https://www.alberta.ca/climate-carbon-pricing.aspx

	In Pillar 2, a carbon tax was not included in the analysis; hence, repealing the Carbon Tax does not change the simulation results.

After an in-depth internal analysis of the impacts of these recent policy/regulations summarized above, it is the opinion of the authors that the results presented in this report are still valid and relevant. The goal of this initiative is to perform objective, comprehensive analyses of the opportunities for Energy Storage in Canada, acknowledging, and attempting to account for, the rapidly changing energy and environmental landscapes. In addition, the methodology and analytical framework presented are intended to be adaptable and open to a wide range of inputs. Therefore, the same framework can be replicated for other provinces, as originally planned for the ES study initiative, to create a consistent basis of analyses. Most importantly, this report is intended to provide information and data that can be used to support informed discussions among a diverse range of stakeholders. The authors believe it still supports that purpose.

Executive Summary

Canada is in the enviable position of being relatively rich in natural resources, and has one of the cleanest, least expensive and most reliable electricity grids in the world. However, an increase in the integration of renewables, a rise in smart grid technologies, and changes in demand and policies at a national and provincial level have created an increased awareness that fundamental changes in the way we build, own and operate our electricity systems may be required, and in many cases, are well underway. Many studies, organizations and experts worldwide have concluded that these changes provide a perfect opportunity for energy storage (ES) technologies to demonstrate their value in supporting energy security and climate change goals, as well as creating a more integrated and optimized energy system. However, given the complexities of the analysis and the marketplace, few comprehensive studies exist at a national or provincial level that comprehensively address the market potential and costs and benefits, in addition to the economic and environmental impacts of significant ES utilization.

Understanding the potential value of ES may help provide cost effective solutions for secure and reliable electric grids, and may also provide opportunities as an economic engine to drive the global competitiveness of Canadian energy products and home-grown expertise. However, most studies undertaken to date have reviewed ES on a project-by-project basis, which makes it difficult to ascertain the full value and costs of implementing the technology. It is within this context that the NRC, through its Energy Storage for Grid Security and Modernization program, has undertaken the development of a Canadian Energy Storage Study, with support and input from the following: NRCan's Office of Energy Research and Development (OERD), strategic partners and consultants, stakeholders across the value chain, and an expert advisory board. This study, consisting of analysis in three pillars (areas of study) is intended to provide a neutral and independent analysis jurisdiction by jurisdiction across Canada that outlines the potential costs and benefits of the adoption of ES technologies. The authors make no policy recommendations in this report. Any conclusions and results should not be interpreted as policy advice. The data and results are meant to support a range of conversations and calculations beyond the scope of this study.

Pillar 1 - Grid Needs and ES Market Opportunity	Pillar 2 - Technology Assessment and Valuation	Pillar 3 - Environmental and Socio-Economic Assessment
• Identify ES use cases • Define specific application requirements • Identify the impacts on grid power planning and operations • Review the current market structure	• Assess ES technologies and trends • Match technology and application requirements • Propose valuation and performance frameworks • Evaluate individual ES profitability and dispatch on the electricity grid	• Assess environmental and socio-economic metrics • Assess GHG emissions at the grid level • Compare life cycle GHG emissions of ES technologies

This study contains the general framework for all jurisdictions, as well as the detailed analysis for Alberta. As the preliminary release of the study, it is expected that the framework and the Alberta chapter will be updated in the future to take into account further refinements based on stakeholder feedback as other jurisdictions proceed, as well as reflect any specific regulatory or technical changes that occur over the duration of the project. Subsequent provinces will be completed independently, due to the varied nature of the markets, generation and supply mix, and providers/technologies used in each market. However, the overall framework will be consistent, and will leverage learning, both across Canadian jurisdictions, and from other early ES markets.

Pillar 1 - Grid Needs and ES Market Opportunity

The 2017 Long Term Outlook report published by Alberta Electric System Operator (AESO) states that Alberta will need significant new investment in electricity generation by 2030 to support the transition toward cleaner sources of energy and meet the electricity needs of a growing province. As one of the most deregulated electricity markets in Canada, Alberta's generation mix by capacity in 2019 consists of approximately 38% Coal, 45% Natural Gas (30% Cogeneration, 10% Combined Cycle, 5% Simple Cycle), 5% Hydro, 9% Wind and 3% Other. The AESO began operating the current energy generation market structure in January 2001, which currently consists of a physical clearing market for all wholesale electricity. In addition to generation, the system is also comprised of regulated transmission and distribution components, as well as a partially deregulated retail component.

This study includes a scenario with a capacity market in Alberta for the purposes of exploring market mechanisms which could impact the adoption of ES technologies. While Alberta currently has no plans to establish a capacity market, the authors felt that this analysis was still valuable to include because it helps to evaluate the business case for various ES technologies under different scenarios. While several initiatives are underway at the AESO and Alberta Energy to manage a transition away from coal, such market changes certainly have the potential to affect wholesale price volatility and impact the adoption of ES technologies.

Key Findings in Pillar 1

- Deploying approximately 1152MW of ES in the Alberta Integrated Electric System (AIES) will help reduce the impact of fuel price volatility and will create a potential net benefit of $155M.
- The cost of ES technology has a significant impact on ES deployment. A 40% reduction in the cost of ES technology will yield a 60% increase in ES deployment.
- Considering load growth in Alberta and the generation retirement/development plan, the costs of ES deployments will become comparable to conventional generation sources in 2024.

Following a production cost modelling approach, optimized for ES analysis without preference to technology, the main findings of this pillar are that selected ES technologies are increasingly attractive for a number of specialized power grid uses, such as operating reserves. The capacity market included in the scenario analysis would increase the value of benefits and project NPV for all ES technologies evaluated, making the energy and capacity markets the second-largest ES benefit after operating reserves. None of the ES services currently possible on Alberta's grid are found to be cost-competitive enough to support a transformational change in Alberta's energy sector away from coal. With consideration to the expected load growth in Alberta and generation retirement / development plan, a scenario of approximately 1152 MW of ES deployment is presented which has a potential net benefit of $155M. This analysis found that electricity prices exhibit less volatility when ES systems are deployed in the bulk electric system. Finally, the cost of ES technology has a significant impact on its level of market penetration – a 40% reduction in ES costs is estimated to yield a 60% increase in ES deployment.

Pillar 2 – Technology Assessment and Valuation

Although at the system-level the AIES operation can be optimally designed to accept ES systems at certain nodes, with certain technology attributes and costs, it is not guaranteed that these deployments of individual storage technologies are equally economically or technically optimized at a project-level. Thus while the analysis in Pillar 1 is technology-agnostic and takes a system level approach to aggregated ES on the AIES, the analysis in Pillar 2 is performed at the project level. It simulates an individual ES technology operating on the AIES with the aim to determine which technologies outlined in Pillar 1 are viable under current and proposed regulation and market guidelines.

In the Pillar 2 analysis, three ES technologies were evaluated that are representative of the more cost-competitive and mature ES options and for which cost and data sets were available from the U.S. DOE: Lithium-ion (Li-ion), Compressed Air Energy Storage (CAES), and Pumped Hydro (P-Hydro). Results are based on given technology lifetimes first normalized to the 14-year study period to select ones for further analysis. Evaluation results were categorized into profitability and dispatch. Second, profitability was further broken down into cost-benefit ratio or Return on Investment (ROI), and Net Present Value (NPV), but over the entire technology lifetime. The greatest ROI was 1.54 or 54% for 15-year Li-ion 10MW 2Hr participating in both AESO's current Energy Market and Ancillary Services Market (except Load Shed Service for imports and Transmission Must Run / Dispatch Down Service) and the estimated Capacity Market. The greatest NPV was $137M for 40-year ($48M normalized to the 14 year study period) CAES 183MW 8Hr participating in the same markets and services.

Three factors that significantly impacted ROI and NPV profitability were technology, markets and services, and financial structure. Regarding technology, cost reductions for Li-ion meant that a one-time stack replacement cost does not significantly impact overall profitability. However, longer technology lifetimes increase multiple major maintenance and repair costs for CAES and P-Hydro, which are mature technologies and do not have significant cost declines.

Key Findings in Pillar 2

- In terms of profitability, without including the AESO Tariffs, ES valuation analysis showed the largest ROI of 1.54 for Li-ion (10MW, 2Hr) and largest Net Present Value of $137M for CAES (40-year 183MW, 8Hr), both operating in Alberta's Markets and Services including the estimated Capacity Market.
- Within Alberta's Markets and Services, Operating Reserves (OR) dominated revenue streams among the three ES technologies evaluated. All three ES technologies also benefitted from participating in the estimated Capacity Market.
- To be profitable, ES must match price and load requirements of markets and services in

terms of response time, capacity, and duration.
- Comparing all NPV's with and without a Capacity Market, NPV decreases on average 24% (+/- 10%). Although a Capacity Market increased NPV for all ES modelled in Pillar 2, it didn't change whether or not that NPV was a profit or a loss.

Higher P-Hydro capital costs relative to those of CAES meant that even for similar energy ratings, P-Hydro was unprofitable (CAES 183MW 8Hr or 26 Hr compared to P-Hydro 280MW 8Hr). Regarding markets and services, price and load data significantly impact the requirements for ES technology response time and the optimal capacity and duration ratings. Of the markets and services studied, proportionately, the largest benefits were from Operating Reserves (OR). It follows that ES technologies that could participate in one or more OR services captured the most benefits, contributing to profitability. OR Regulating dominated for fast response ES such as Li-ion, and OR Contingency Supplemental dominated for slower response technologies such as CAES. All ES technologies participating in the estimated Capacity Market showed an increase in profitability, although not as large as for OR. Increasing the duration of a simulated CAES system (183MW capacity) from 8Hrs to 26Hrs increased revenues within the Transmission Deferral sub scenario, but at the expense of overall NPV. Hence there is an opportunity cost because the main value is in shorter duration services and longer ES duration does not support the increase in capital cost. Switching to P-Hydro, when compared to Pillar 1's maximum ES market size of 1152MW 4.74Hr, the energy of the 900MW 16Hr P-Hydro unit made it larger than the energy demand from AIES' Energy Markets and Ancillary Services, rendering that P-Hydro unit unprofitable. Regarding financial structure, a 12% Return on Equity (ROE) made Capital Expenditures (Equity) the largest cost for the combustion turbine (CT) and ES technologies studied. A high ROE coupled with the longer lifetime, larger capacity, and higher capital cost of P-Hydro ES technologies meant their Capital Expenditure (Equity) costs increased faster than their revenues.

It was found that long duration markets and services have the highest ES usage, however, these do not necessarily generate the largest revenues. Multiple sub-hourly grid services such as OR can provide the largest revenues. However, in the case of Li-ion Regulating Reserves, they can pose the risk of significant wear and tear on the system, possibly reducing stack lifetime. In the case of Li-ion's cycle counts and Depth of Discharge (DoD), the largest number of cycles was at DoDs that corresponded to sub-hourly dispatch (3% DoD) and at least hourly dispatch (20% and 40% DoD) for various grid services. These hourly and sub-hourly services potentially reducing stack lifetime were represented by the combined effects of participating in operating reserves, energy and capacity markets.

Pillar 3 - Environmental and Socio-Economic Assessment

Economy

Many industry reports predict ES costs to decrease significantly over the next five years, driven by scale and related cost savings, improved standardization and technological improvements, and supported in turn by increased demand as a result of regulatory / pricing innovation, high renewables penetration, interests in system operators to seek non-wires solutions, and the needs of an aging and changing power grid in the context of a modern society.

As global ES markets continue to evolve, several potential sources of revenue available to ES systems have emerged, and ultimately, the mix of available revenue streams for a particular ES system varies significantly across jurisdictions.

Regarding the socio-economic impacts of ES deployment, most economic impacts are generated during the construction phase, similar to the impacts that occur during the deployment of renewable energy projects. During the construction phase, ES projects are expected to create 2,853 jobs from 2021 to 2030 (based on Pillar 3 analyses described in this report). However, the economic impact is likely to be lower than the economic impact in, for example, solar PV projects, as ES systems are usually modular and imported with lower construction-phase costs.

Environment

The projected incremental environmental benefits from ES deployment in the Alberta electricity system are not significant in comparison to the projected GHG emissions reductions of the Alberta electric grid from 2017 to 2030 due to other factors including coal phase-out and renewable energy additions. The grid-level GHG emissions without ES decrease by 45% while system-level GHG emissions with ES decrease by 46%.

Key Findings in Pillar 3

- The incremental GHG benefits from ES deployment are negligible in comparison to the projected GHG emissions reductions of the Alberta electricity system from 2017 to 2030 from new renewables and coal phase-out. The grid-level GHG emissions decrease annually by an average of 4% from the previous year.
- The GHG life cycle impact of Li-ion battery ES systems are mostly due to the emissions during manufacturing (cradle-to-gate stage) of the ES system components, specifically the battery pack.

The comparative life cycle GHG impact between Li-ion battery systems and CAES systems indicates that Li-ion battery systems are more environmentally friendly than CAES systems, and Li-ion batteries generate approximately 22% - 24% less GHG emissions than CAES systems.

The overall contribution of the operations stage to the overall life cycle impact depends upon the round-trip efficiency alongside the changes on the power-grid mix. In the case of CAES systems, it is predicted that CAES has noticeably higher emissions during the operations phase, when emissions originate from natural gas combustion during system operations and are exacerbated by low CAES system round-trip efficiency.

Due to the cradle-to-gate impact, further study is recommended to perform a comparative analysis of GHG life cycle impact on ES systems for different ES technologies and grid services. GHG use-phase impact is affected by the variations in emission intensities in the power-grid mix when the ES system is charged and discharged according to a specific grid service requirement.

Résumé

Le Canada a de quoi se réjouir, car il est relativement riche en ressources naturelles et dispose d'un des réseaux électriques les plus propres, les moins chers et les plus fiables au monde. Pourtant, l'exploitation croissante des énergies renouvelables, l'essor des technologies de réseaux électriques intelligents et l'évolution de la demande et des politiques nationales et provinciales ont suscité une conscientisation accrue sur le besoin d'apporter des changements fondamentaux dans la manière dont nous construisons, possédons et exploitons nos systèmes électriques. Dans un grand nombre de cas, ces changements sont d'ailleurs largement entamés. De nombreux études, organisations et spécialistes dans le monde ont conclu que de tels changements constituent l'occasion rêvée de montrer l'utilité des technologies de stockage de l'énergie (SE), non seulement dans la réalisation des objectifs liés à la sécurité de l'énergie et au changement climatique, mais aussi dans la genèse d'un circuit de

l'énergie optimisé et mieux intégré. Malheureusement, face aux complexités de l'analyse et du marché, peu d'études nationales ou provinciales examinent de façon exhaustive les avantages et les coûts potentiels du SE, sans parler de son impact sur l'économie et l'environnement.

Préciser la valeur éventuelle du SE nous aiderait à apporter des solutions rentables pour des réseaux d'électricité sûrs et fiables. Parallèlement, un tel exercice mettrait en relief les possibilités du SE en tant que moteur économique susceptible d'accroître la compétitivité des produits énergétiques canadiens et de l'expertise locale dans le monde. Toutefois, la plupart des études réalisées jusqu'à présent ne se penchent que sur des projets particuliers, si bien qu'il est difficile d'établir globalement la valeur et le coût de la mise en œuvre des technologies de SE. C'est dans ce contexte que le CNRC, par le truchement de son programme « Stockage d'énergie pour la sécurisation et la modernisation des réseaux », a entrepris une étude sur le stockage de l'énergie au Canada. Il a pour cela bénéficié de l'aide et de l'apport du Bureau de recherche et de développement énergétiques (BRDE) de RNCan, de partenaires stratégiques et d'experts-conseils, des intervenants de toute la chaîne de valeur et d'une commission consultative d'experts. L'étude porte sur trois axes (champs de recherche) et avait pour but de brosser un tableau objectif et indépendant des avantages et inconvénients potentiels de l'adoption des technologies de SE au Canada, dans chaque province ou territoire. Les auteurs ne formulent aucune recommandation. Leurs conclusions ou résultats ne devraient en aucun cas être interprétés comme des conseils pour orienter les politiques publiques. Ils n'ont d'autre but qu'alimenter la discussion et pousser la réflexion au-delà des objectifs immédiats de l'étude.

1er axe — Besoins du réseau et débouchés possibles pour le SE	2e axe — Évaluation et appréciation des technologies	3e axe — Retombées environnementales et socioéconomiques
•Établir les utilisations du SE •Préciser les contraintes d'ordre pratique •Établir l'impact sur la planification et l'exploitation du réseau •Examiner la structure actuelle du marché	•Évaluer les technologies de SE et les tendances •Jumeler les technologies aux contraintes pratiques •Proposer un cadre pour l'évaluation et le rendement •Déterminer le seuil où une technlogie devient rentable ou pas dans le réseau	•Évaluer les paramètres environnementaux et socioéconomiques •Déterminer la quantité de GES libérée par le réseau d'électricité •Comparer le cycle de vie des émissions de GES des technologies de SE

Cette étude propose un cadre général pour toutes les compétences, ainsi qu'une analyse détaillée de la situation en Alberta. Puisqu'il s'agit de sa première mouture, le cadre et la partie sur l'Alberta devraient ultérieurement être peaufinés d'après les commentaires formulés par les intervenants à mesure que les compétences s'impliquent ainsi qu'en fonction de la manière dont les techniques et la réglementation évoluent durant le projet. Plus tard, on brossera un portrait distinct de la situation dans les autres provinces, car la nature du marché varie, de même que le mélange des capacités de production et des sources d'approvisionnement, et les fournisseurs/technologies qui composent le marché. Le cadre général restera cependant le même et sera bonifié par les enseignements tirés des diverses compétences canadiennes, de même que d'autres débouchés initiaux du SE.

1er axe — Besoins du réseau d'électricité et débouchés possibles pour le SE

Le rapport de 2017 sur les perspectives à long terme publié par l'Alberta Electric System Operator (AESO) indique que cette province devra investir de façon appréciable dans la production d'électricité d'ici à 2030 pour faciliter le passage vers des sources moins polluantes tout en satisfaisant la demande d'électricité d'une population en pleine croissance. L'un des marchés les plus déréglementés du pays, le marché albertain de l'électricité de 2019 se caractérisait par une capacité de production qui se répartit comme suit : 38 % du charbon, 45 % du gaz naturel (30 % pour la production combinée, 10 % pour la production par cycle combiné et 5 % pour la production par cycle simple), 5 % de l'hydroélectricité, 9 % du vent et 3 % d'autres sources. L'AESO a commencé à exploiter la structure actuelle du marché de la production d'énergie en janvier 2001, qui consiste actuellement en un ajustement du marché en fonction de l'offre et de la demande pour toute l'électricité vendue en gros. Outre la production, le système comprend également des composantes de transport et de distribution réglementées, ainsi qu'une composante de détail partiellement déréglementée.

L'étude comprend un scénario dans lequel l'Alberta est dotée d'un marché de production, le but étant d'explorer les mécanismes qui pourraient influer sur l'adoption des technologies de SE. Bien que la province ne caresse absolument pas l'intention de passer à un marché de production pour l'instant, les auteurs croient qu'une telle analyse présente de l'intérêt, car elle facilite l'évaluation de diverses technologies de SE dans différentes situations. Quoique l'AESO ait lancé plusieurs initiatives et que l'organisme public Alberta Energy doive gérer le passage du charbon à de nouvelles sources d'énergie, nul ne niera que des changements de ce genre, sur le marché, auront une influence sur la volatilité du prix de gros et sur l'adoption des technologies de SE.

Principales constatations du 1er axe

- Le déploiement d'installations capables de stocker environ 1 152 MW d'électricité dans l'Alberta Integrated Electric System (AIES) rendrait le prix des combustibles moins volatil et engendrerait un bénéfice net potentiel de 155 M$.
- Le coût de la technologie de SE a un impact notable sur son déploiement. En réduisant ce coût de 40 %, le déploiement s'élargirait de 60 %.
- Étant donné la progression de la demande en Alberta et les plans de développement ou de désaffection des installations de production, en 2024, il en coûtera autant pour déployer une technologie de SE que pour produire de l'électricité de la manière usuelle.

Lorsque l'on recourt à un modèle qui repose sur le coût de production, optimisé pour l'analyse du SE, toutes technologies confondues, on constate que certaines technologies présentent de plus en plus d'attrait pour des activités précises, associées au réseau d'électricité, entre autres les réserves d'exploitation. Le marché de production, à la base du scénario de l'analyse, valoriserait les avantages et augmenterait la valeur actualisée nette (VAN) prévue de toutes les technologies de SE examinées. Le marché de production et celui de l'énergie en récolteraient les plus grands fruits, après les réserves d'exploitation. Aucun des services de SE qui pourraient voir le jour sur le réseau albertain n'est assez concurrentiel pour amener un changement qui transformerait le secteur de l'énergie provincial en l'affranchissant du charbon. Compte tenu de la hausse de la charge prévue dans la province et des projets de développement/désaffection d'installations de production, le scénario envisage le déploiement d'installations capables de stocker environ 1 152 MW d'électricité, avec un bénéfice net potentiel de 155 M$. L'analyse indique que le déploiement de systèmes de stockage d'énergie à la grandeur du réseau, ou presque, rendrait le prix de l'électricité moins volatil. Enfin, le coût de ces technologies influe de manière notable sur leur degré de pénétration sur le marché. Ainsi, une baisse de 40 % de leur coût déboucherait, estime-t-on, sur une hausse de 60 % au niveau du déploiement.

Deuxième axe — Évaluation et appréciation des technologies

Même si l'on réussissait à optimiser l'exploitation de l'AIES dans son ensemble pour que l'on puisse y intégrer des installations de SE à des points névralgiques, sous réserve des propriétés et du coût de la technologie, rien ne garantit que le déploiement d'une technologie de stockage ou une autre est aussi économique ou techniquement optimale au niveau du simple projet. C'est pourquoi, alors que l'analyse réalisée dans le cadre du premier axe est technologiquement agnostique et suit une approche systémique à l'intégration du SE à l'AIES, celle du deuxième axe s'effectue au niveau du projet. Cette analyse simule une technologie de SE intégrée à l'AIES pour déterminer les technologies du premier axe qui seraient rentable, étant donné la réglementation existante et celle envisagée, et les lignes directrices du marché.

Trois technologies de SE parmi les plus matures et économiquement les plus concurrentielles pour lesquelles on dispose de données sur le coût et d'autres aspects, grâce au département de l'Énergie américain, ont ainsi été évaluées : les batteries au lithium ionique (Li-ion), le stockage par air comprimé (CAES) et les centrales à réserve pompée (P-Hydro). Les résultats s'appuient sur la vie utile de la technologie, d'abord uniformisée pour la période de 14 ans de l'étude, afin de faciliter le choix de celles qui feraient l'objet d'une analyse plus poussée. Les résultats de l'évaluation ont été divisés en deux : technologie rentable ou pas rentable. Ensuite, la catégorie « rentable » a été subdivisée d'après le ratio coût/avantage ou le rendement du capital investi (RCI), et la valeur actualisée nette (VAN) pour la vie entière de la technologie. Le meilleur RCI (1,54 ou 1,54 %) est celui du stockage de 10 MW pendant 2 h dans des batteries au lithium ionique sur une période de 15 ans, sur le marché de l'électricité et des services auxiliaires de l'AESO (excepté le Load Shed Service — service de délestage instantané — et le Transmission Must-Run/Dispatch Down Service — service de transmission obligatoire/de vente sous contrat) et sur le marché de production estimé. La plus grande VAN se chiffrait à 137 M$ pour le stockage de 183 MW par air comprimé pendant huit heures sur une période de 40 ans (48 M$ lorsque l'on ramène la VAN à la période de 14 ans de l'étude), pour les mêmes marchés et services.

Trois facteurs ont un impact prononcé sur le RCI et la VAN : la technologie, le marché et les services, et la structure financière. En ce qui concerne le premier, la réduction du coût des batteries au lithium ionique ferait en sorte que ce qu'il en coûte pour remplacer une seule fois les batteries n'aurait pas d'influence significative sur leur rentabilité. En revanche, une vie utile plus longue verrait divers coûts d'entretien et de réfection importants augmenter pour le CAES et la P-Hydro, deux technologies matures dont le coût ne devrait pas diminuer de manière appréciable.

Principales constatations du 2e axe

- Sur le plan de la rentabilité, si l'on exclut les tarifs de l'AESO, l'évaluation des technologies de stockage d'énergie montre que les batteries au lithium ionique (stockage de 10 MW sur 2 h) produisent un meilleur RCI (1,54) et une plus forte valeur actualisée nette (137 M$) que le CAES (sur 40 ans, stockage de 183 MW sur 8 h), pour les marchés et les services de l'Alberta, dont un éventuel marché de production.
- Parmi les marchés et services albertains, les réserves d'exploitation sont celles qui engendrent les meilleurs revenus pour les trois technologies de SE évaluées. Ces technologies profiteraient aussi de leur intégration au marché de production éventuel.
- Pour être rentable, cette technologie doit satisfaire aux contraintes de prix et de charge des marchés et des services (réactivité, capacité, durée).
- La VAN diminue en moyenne de 24 % (±10 %) selon l'existence ou pas d'un marché de production. Bien que le marché de production hausse la valeur actualisée nette de toutes les technologies modélisées dans l'analyse du 2e axe, il ne modifie en rien la rentabilité ou pas de la technologie en question.

Le coût en capital plus élevé de la P-Hydro, comparativement à celui du CAES signifie que, même avec une cote énergétique identique, les centrales à réserve pompée n'atteignent pas le seuil de rentabilité (183 MW sur 8 h ou 26 h pour le CAES contre 280 MW sur 8 h pour la P-Hydro). Sur le plan des marchés et des services, les données indiquent que le prix et l'importance de la charge ont une influence notable sur la réactivité requise des technologies de SE ainsi que sur leur capacité optimale et la durée. Parmi les marchés et les services examinés, les plus grands avantages vont proportionnellement aux réserves d'exploitation. On en déduit que les technologies de SE qui pourraient être intégrées à un ou plusieurs de ces services sont celles qui récoltent le plus de bénéfices, donc concourent davantage à la rentabilité. Les technologies de SE fort réactives comme les batteries au lithium ionique conviennent le mieux aux réserves d'exploitation réglementées, tandis que celles à moins grande réactivité comme le CAES se prêtent davantage aux réserves d'exploitation supplémentaires d'urgence. Toutes les technologies de SE employées sur le marché de production à l'étude connaissent une hausse de rentabilité, même si elle n'est pas aussi marquée que pour les réserves d'exploitation. Quand la durée de stockage du système du CAES (capacité de 183 MW) passe de 8 à 26 h dans la simulation, on note une hausse des revenus dans le scénario secondaire du report de transmission, mais cette hausse se fait aux dépens de la valeur actualisée nette globale. Il existe donc un coût de renonciation. La raison est que la valeur se concentre surtout dans les services de courte durée et qu'un plus long stockage ne compense pas le coût en capital plus élevé des technologies. Du côté de la P-Hydro, lorsque l'on compare cette technologie à la taille maximale du marché du stockage d'énergie du premier axe (1 152 MW pendant 4,74 h), on se rend compte que les 900 MW stockés pendant 16 h par la centrale P-Hydro sont supérieurs à la demande pour le marché de l'énergie et les services auxiliaires de l'AIES. La technologie n'est donc pas rentable. En ce qui concerne la structure financière, un rendement des capitaux propres (RCP) de 12 % fait des dépenses d'immobilisation (DI) le coût le plus élevé pour la turbine à combustion (TC) et les technologies de SE examinées. Si l'on y ajoute une vie utile plus longue, une plus grande capacité et un coût en capital supérieur, le RCP élevé de la P-Hydro signifie que les dépenses d'immobilisation associées à cette technologie de SE augmentent plus vite que les recettes. Les marchés et les services de longue durée sont ceux qui recourent le plus au SE. Cependant, ils ne produisent pas nécessairement les revenus les plus importants. Beaucoup de services de réserves d'exploitation de moins d'une heure peuvent en effet engendrer les revenus les plus intéressants. Les réserves réglementées des batteries au lithium ionique peuvent néanmoins s'accompagner d’un risque d’usure important pour le réseau, ce qui en réduirait la vie utile. Le nombre de cycles le plus élevé pour ces batteries s’observe aux profondeurs de décharge qui correspondent à une décharge subhoraire (3 % de la profondeur de décharge) et à une production sous contrat au moins horaire (20 % et 40 % de la profondeur de décharge) pour divers services du réseau. Les services horaires et subhoraires susceptibles de raccourcir la vie utile des batteries sont ceux qui combinent la participation aux réserves d’exploitation, au marché de l’énergie et au marché de production.

Troisième axe — Évaluation environnementale et socioéconomique

Économie
De nombreux rapports de l’industrie prévoient une forte diminution du coût du stockage d’énergie au cours des cinq prochaines années, en raison des économies d’échelle qui abaisseront les coûts, d’une meilleure uniformisation et des perfectionnements techniques, le tout étant appuyé par une hausse de la demande attribuable aux innovations sur les plans de la réglementation et des prix, à une forte pénétration du marché par les sources d’énergie renouvelable, au désir des exploitants de trouver des solutions qui les affranchiront des lignes de transport et aux besoins d’un réseau d’électricité vieillissant qui s’adapte à la société contemporaine.

Avec l’évolution des marchés du stockage d’énergie dans le monde, plusieurs débouchés potentiels ont vu le jour pour les systèmes de SE, de sorte que les possibilités de revenu d’un système donné varient passablement d’un endroit à l’autre.

Du côté des retombées socioéconomiques, la plupart des impacts d’un déploiement du SE sur l’économie sont enregistrés pendant la construction, comme c’est le cas lors du déploiement des projets touchant l’énergie renouvelable. En effet, la phase de construction des projets de SE devrait engendrer 2 853 emplois de 2021 à 2030 (selon les analyses du troisième axe décrites dans le rapport). Cependant, ces retombées se matérialiseront sans doute plus lentement que celles, par exemple, des projets de production solaire d’énergie photovoltaïque, car les systèmes de stockage d’énergie sont souvent modulaires, ce qui entraîne de moins grands coûts de construction.

Environnement

Le déploiement prévu du SE dans le réseau d'électricité albertain ne présentera que des avantages minimes pour l'environnement, comparativement à ceux que devraient entraîner la baisse du volume de GES libéré par le réseau entre 2017 et 2030 résultant d'autres facteurs, dont l'abandon du charbon et l'intégration de sources d'énergie renouvelable. Les émissions de GES du réseau devraient reculer de 45 % sans SE contre 46 % avec le SE.

Principales constatations du 3e axe

- Le déploiement du stockage d'énergie n'améliorera la situation des GES que de façon négligeable, comparativement à la réduction des émissions que l'intégration de nouvelles sources d'énergie renouvelable au réseau d'électricité albertain et l'abandon du charbon devraient entraîner entre 2017 et 2030. La quantité de GES libérée par le réseau devrait baisser en moyenne de 4 % par année.
- L'impact des systèmes de SE à batteries au lithium ionique sur les GES durant leur vie utile résultera principalement de la fabrication (de l'idée au marché) des composants, surtout les blocs de batteries.

Lorsque l'on compare l'incidence des batteries au lithium ionique sur les GES durant leur vie utile à celle du CAES, on constate que les premières sont moins dommageables que le second. En effet, les batteries au lithium ionique libèrent environ de 22 % à 24 % moins de GES que le CAES.

La part que la phase d'exploitation d'une technologie apporte à l'impact environnemental global de cette dernière dépend du rendement général de la technologie en question et des changements qu'elle apporte à la composition du réseau d'approvisionnement en électricité. Pour le CAES, des émissions passablement plus importantes doivent être prévues durant la phase d'exploitation, surtout si le système brûle du gaz naturel pour stocker l'électricité. Cette situation sera exacerbée par le rendement global peu élevé des technologies de CAES.

En raison de l'impact « de l'idée au marché », on préconise une analyse comparative plus poussée des répercussions globales du stockage d'énergie sur les GES pour différents services d'électricité et technologies de SE. Le fait que l'intensité des émissions varie lorsque l'on charge et décharge les systèmes de SE en fonction des besoins du réseau modifiera l'impact de la phase d'exploitation sur le volume de GES.

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Introduction

The National Research Council Canada (NRC) and its partners are embarking on a 5-year project to develop a Canadian Energy Storage Study. This work builds upon previous work in Canada and internationally to perform a comprehensive independent analysis of the potential costs and benefits of adopting Energy Storage (ES) technologies in each jurisdiction. In order to do this in a uniform fashion and ensure a fact-based approach to the detailed assessment of the various factors under consideration, the project team is focusing on three pillars of analysis, shown in Figure 1. This common framework will be applied to each province in turn, and released as chapters of the overall Canadian Energy Storage Study.

Pillar 1 - Grid Needs and Market Opportunity	Pillar 2 - Technology Assessment and Valuation	Pillar 3 - Environmental and Socio-Economic Assessment
• Identify ES Use Cases • Define specific application requirements • Identify the impacts on grid power planning and operations • Review the current market structure	• Assess ES technologies and trends • Match technology and application requirements • Propose valuation and performance frameworks • Evaluate individual ES profitability and dispatch on the electric grid	• Assess environmental and socio-economic metrics • Assess GHG emissions at the grid level • Compare life cycle GHG emissions of ES technologies

Figure 1: Three pillars of analysis in the Canadian Energy Storage Study project

Across all three pillars, engagement of key stakeholders such as regulators, power producers, and policy makers, along with storage technology vendors and system integrators, is critical. This has been initiated through the creation of an advisory board which has members from many key organizations. Given that the project is ongoing over a number of years, it is expected that the project team will continue to identify and engage key stakeholders within each province, assess particular stakeholder needs and opportunities, organize and document stakeholder input, and disseminate study results. This study will also leverage recent Program of Energy Research and Development (PERD) projects (2A02.002, NRESOT-04 and NRESOT-05), focusing on real time load data collection and analysis, a CanmetENERGY project on the Canadian ancillary services market, and an NRC TEA (Techno Economic Analysis) platform including a Canadian ES valuation tool and databases therein (ES-Select Canada).

Results for each province will be completed independently due to the varied nature of the markets, generation and supply mix, and providers / technologies used in each market. However, the overall framework will be consistent and will leverage learning across Canadian jurisdictions, as well as from other early ES markets such as California and PJM in the Eastern U.S.

As outlined in the detailed project scope below, the project will be completed in phases, starting with overall framework development, applying it first in Alberta and then Ontario, and then moving to the other Canadian jurisdictions. These individual chapters will then be capped by an overall national picture of ES and its impact on the electricity grid. The current report is focused on ES market opportunities in Alberta.

The goal of this analysis will be to allow the market to compete in an open and fair manner, both for ES technologies and for existing assets and technologies. More specifically, it is expected that this analysis will produce the following results:

- Pillar 1 result: A clear understanding of the market need for the services that ES might provide in each jurisdiction, at the generation, transmission, and distribution levels, including the development of standardized use cases.
- Pillar 2 result: An assessment of the realistic market opportunity for ES, including an analysis of the current and future state of the art of individual technologies, the value of each technology in individual use cases, and the identification of specific regulatory or market barriers that might prevent deployment.
- Pillar 3 result: A uniform assessment of the environmental and economic impacts of the adoption of ES, including the possibility of increased engagement of the electricity and manufacturing sectors in new technology commercialization, both for local use and export opportunities.

1 Grid Needs and Market Opportunity Pillar

Pillar 1 is a macro-level analysis that generates outputs that are used by the other two Pillars. The Pillar 1 analysis identifies ES use cases, defines specific application requirements, and identifies the impacts on grid power planning and operations. Details on the Pillar 1 objectives, background, methodology, and results are found in the sections below.

1.1 Introduction to Pillar 1

The ES industry is seen by many analysts and advocates to be rapidly advancing with regard to cost, performance, and market penetration. This is mainly based on various analyses which show that ES provides various benefits to an electricity grid/market. Therefore, many project developers and planners are looking to ES in order to increase resiliency and reliability, and help end users manage energy costs in utility, commercial and consumer markets. According to a report compiled by Bloomberg New Energy Finance and IEA, in 2016 there were 5 GWh of ES installed globally (excluding pumped hydro), and this number is expected to grow to 300 GWh by 2030[5].

The objective of Pillar 1 of this study is to perform an independent analysis of the potential benefits and costs of implementing ES. The analysis involves optimizing the size, location, and timing of potential ES deployments on the Alberta grid in order to maximize the benefits to the ratepayers in the province of Alberta over the study time horizon of 2017 to 2030. The study also considers various policy changes and goals, both existing and expected at a federal and provincial level.

In order to achieve these goals, the NRC, with the support of organizations on the Advisory Board, the Contributing Partners Committee, and Acelerex Consulting, conducted a technology-agnostic ES production cost model analysis for the province of Alberta. This analysis extended the 2017 Alberta Long Term Outlook[6] to specifically look at the potential value streams that ES might provide over the long-term, while comparing this to the overall cost of deployment and operation. Various ES benefits were evaluated, including opportunities to reduce the price paid for electricity usage, reduce peak demands, avoid the cost of transmission and distribution investments, avoid capital investments in new capacity, increase renewable penetration, and reduce GHG emissions.

This study required a large amount of grid and market data which was collected from various sources including federal and provincial governments, industry representatives, and internationally-accepted benchmarking reports. From these data, a large-scale, complex co-optimization model was built to simulate various scenarios of ES development in Alberta.

The results of this pillar are the total potential market size for ES in the province including an optimization of the location, type, and timing of ES deployments that would result in the lowest-cost system given the scenarios and assumptions that have been outlined below. It should be noted that changes to the market, technology, or policies, or increased scope of the study to include other storage technologies or sites (such as ES specifically optimized to be distributed behind the meter) may provide a different view than that presented in this study.

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[5] https://www.greentechmedia.com/articles/read/global-energy-storage-double-six-times-by-2030-matching-solar-spectacular#gs.KvJY1h0

[6] Alberta Long Term Outlook 2017

1.2 Background

A considerable amount of information and data was required to inform the analyses under Pillar 1. The sections below contain detailed information on the considerations used to define the scope of the analyses, the benefit categories and potential use cases, and the referenced studies and analyses.

1.2.1 Economic, Policy, Market, and Technical Considerations

In order to be able to define the most reasonable study scenario, it is important to first consider the environment under consideration and determine the fixed inputs to the model. For pillar 1, these largely relate to specific external drivers and assumptions in Alberta regarding:

- Economic Forecasts
- Federal and Provincial Policies
- Grid Topology
- Electricity Market Operation

Where possible, inputs to the analysis were checked for consistency with a number of previous studies and policy documents, such as the Alberta Long Term Outlook, and other similar studies referenced in section 5. Throughout this document, where specific values are listed, references are provided back to those documents, or summarized in tables so that any follow-on analysis, or discussion can use the information provided herein as a basis for further analysis and study.

In the subsections that follow, short summaries of the various drivers and assumptions used in the analysis are provided.

1.2.1.1 Economic Drivers and Assumptions

It is widely acknowledged that the overall strength of Alberta's economy is heavily dependent upon oil sands projects in the province. When oil prices drastically decreased from U.S. $100 plus per barrel in 2014 to approximately $50 per barrel in 2016 due to a global oil supply surplus, it was expected that less capital investment would be made available to new or existing oil sands projects in Alberta. As a result, the 2017 long-term outlook published by the AESO anticipated a relatively low load growth for the Alberta grid over the study period. In this study, there are no independent economic assumptions used that are not specifically reliant on the analysis already provided in the long-term outlook.

1.2.1.2 Policy Drivers and Assumptions

Electricity in Canada is provincially regulated. However various policies at both a provincial and federal level affect the electricity market, and therefore the cost/benefit of storage, both directly through market design (as outlined in the following section), and also indirectly through a number of other regulations impact the economic and/or environmental viability of particular projects.

1.2.1.3 Federal Policy Drivers

Alberta, being rich in coal reserves and having strategically located coal-fired generation facilities, has historically made coal one of the cheapest energy sources for electricity generation in the province. However, as of 2015, coal-fired generating plants in Alberta were responsible for 48.5% of the total GHG emissions from electricity generation in Canada. At the federal level, a mandate to improve Canada's environmental sustainability over time has increased the focus on existing assets on the grid and their emissions. Enabled by the Canadian Environmental Protection Act, the “Federal Coal Regulation”[7], first introduced in 2012, aims to reduce the emission intensities of coal-fired generation across Canada. Most recently, a Regulatory Impact Analysis Statement was published in the Canada Gazette in February 2018 which outlined the potential impacts of proposed amendments to the regulation which would require that all coal-fired units meet the performance standard of 420 t of CO_2/GWh by 2030[8]. Based on this and other provincial regulations outlined below, 5 out of the 18 operating coal units in Alberta as of 2017 are expected to shut down by 2030. Recently, plans have been announced, and work has begun, to convert and/or repower coal-fired units to natural gas. Once these conversions are complete, the plants would then fall under “Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity” [9], which were developed in parallel to the coal regulations. Based on current policy, it is reasonable to assume that all coal-fired generation facilities will either be converted or retired by the end of 2030[10]. Therefore, a firm removal schedule was utilized in this study based on the data collected from stakeholders (see Appendix XV**).**

In October 2016, the federal government announced a pan-Canadian approach to carbon pricing under the “Pan-Canadian Framework on Clean Growth and Climate Change”[11]. At that time, carbon pricing was in place in four provinces, including Alberta. All other provinces also committed to adopt some form of carbon pricing. This was then followed by a draft legislative proposal for the “Greenhouse Gas Pollution Pricing Act” [12] in January 2018 for public comment. Outlined in the proposed legislation were federal tax rates for various types of fossil fuels used for combustion across a number of industries including electricity generation starting at $10/tonne CO_2 equivalent in 2019 and increasing by $10/tonne per year to $50/tonne in 2023. Additionally, the legislation includes a proposed output-based pricing system for large emitters based on national averages in their industry instead of the carbon tax outlined above. However, of note is that the legislation only applies to provinces and territories which do not have their own carbon pricing plans, or where the plans do not meet the minimum standard of the proposed legislation. At the time of this report, given that Alberta is one of the 4 provinces which has an existing pricing system, the impacts and assumptions of this policy are outlined in section 1.2.1.4 below.

1.2.1.4 Provincial Policy Drivers

In 2007, Alberta was one of the first jurisdictions in North America to implement a law requiring reductions in emissions intensities of large final emitters. The *Climate Change and Emission Management Act* and its regulations[13] required companies to make operating improvements, buy Alberta-based credits, or contribute to the Climate Change and Emissions Management fund. Currently managed by Emissions Reductions Alberta (ERA), the fund takes investments from industry at the current price of $30/tonne CO2 equivalent, and invests in

[7] http://laws-lois.justice.gc.ca/eng/regulations/SOR-2012-167/index.html

[8] http://www.gazette.gc.ca/rp-pr/p1/2018/2018-02-17/html/reg3-eng.html

[9] http://gazette.gc.ca/rp-pr/p1/2018/2018-02-17/html/reg4-eng.html

[10] AESO 2017 Long-term outlook

[11] https://www.canada.ca/en/services/environment/weather/climatechange/pan-canadian-framework/climate-change-plan.html

[12] https://www.canada.ca/en/environment-climate-change/news/2018/01/output-based_pricingsystemregulatoryframework.html

[13] https://open.alberta.ca/publications/c16p7

clean technology projects through a RFP process. Some of these projects include ES, and as a result, in 2015/16 ERA undertook a study in partnership with Alberta Innovates, and SOLAS Energy Consulting Inc. The study analyzed the potential for GHG emissions reductions from the use of ES, including reviewing the detailed methodology for measurement of emissions reductions on a project-by-project basis.[14] Additional information regarding this study is provided in section 1.2.3 below. In partnership with Alberta Innovates and SOLAS, where possible, alignment was created between inputs and assumptions in both studies.

Since 2009, micro-generation in Alberta has increased on average by 70% each year. In December 2016, changes to the Micro-Generation Regulation were released by the Alberta Government. These changes increased flexibility and opportunities for micro-generation facilities by allowing renewable generation and alternative energy sources to serve adjacent sites and increase the capacity limit from 1MW to 5MW. These changes are factored into the model such that generation facilities in this size range can be added to the bulk system[15].

The Carbon Competitiveness Incentive Regulation[16], which replaced the Specified Gas Emitters Regulation on January 1, 2018, aims to reduce emissions intensities, and ensure there is equivalency with the federal pan-Canadian emissions framework outlined in section 1.2.1.3 above. The regulation applies to facilities that emit 100,000 tons or more of greenhouse gases per annum, and allows smaller facilities to opt in if they meet certain guidelines. The regulation employs an output-based allocation, and for electricity generation it specifies a "good-as-best-gas" benchmark, which is equivalent to the least emissions-intensive, natural gas-fired generation system in the province. The carbon pricing in this study assumes compliance with current provincial carbon pricing regulation, which utilizes a fixed price of \$30/tonne CO_2 equivalent from 2018 to 2030. Additional increases towards the federal target of \$50/tonne CO_2 equivalent by 2023 have not been included in this initial analysis due to uncertainty regarding the details of the provincial plan for compliance with federal regulation. This simplification is intended to provide a storage conservative perspective on the thermal generation changes in the Alberta grid, and the value can be updated in future analyses as required. Additional information regarding the details of carbon pricing with respect to GHG emissions targets are provided in Pillar 3 under section 3.2.1.1.

The CCIR is planned to be replaced by the Technology Innovation and Emissions Reduction (TIER) system on January 1, 2020. TIER is intended to encourage energy-intensive industrial entities to reduce their emissions through investments in innovative clean technologies[17].

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[14] http://energystorageactivity.ca/region/alberta/rand/energy-storage-and-renewable-energy-alberta-analysis-potential-greenhouse-gas

[15] **http://www.auc.ab.ca/regulatory_documents/Pages/Microgeneration.aspx**

[16] https://www.alberta.ca/carbon-competitiveness-incentive-regulation.aspx

[17] https://www.alberta.ca/technology-innovation-and-emissions-reduction-engagement.aspx

1.2.1.5 Electricity Market Conditions

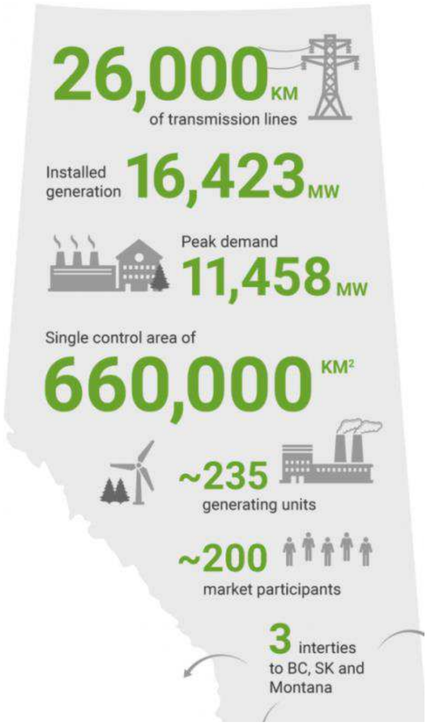

Figure 1-1: Alberta Integrated Electricity System Summary

Alberta has one of the most deregulated electricity systems in Canada. The creation of the current energy-only market from a system which was previously operated by three vertically integrated utilities began in 1996, with full deregulation in 2001. The Alberta Electric System Operator (AESO) is the independent system operator in Alberta, and currently operates wholesale markets, along with providing planning and reliability services as balancing authority and reliability coordinator. It ensures fair and open access to the transmission system for all market participants through a number of policy and stakeholder engagement processes. In addition to the AESO, the Alberta Utilities Commission holds the regulatory responsibility, and the Market Surveillance Administrator (MSA) provides a surveillance function for the market.

The Alberta wholesale electricity market follows an energy-only model. In this model, generators are paid for the electricity they produce using a real-time competitive offer process. The resulting merit order of offers from generators is then managed by the AESO on an hourly basis as it distributes power throughout the province. Dispatch of energy starts at the lowest price offered until demand is met hour-by-hour, resulting in an equilibrium value where the price is set at the margin between generation supply and load demand. Additionally, there is an Ancillary Services Market, where the AESO procures ancillary services from market participants to keep the transmission system running reliably and securely. Ancillary services include Operating Reserve, Transmission Must-Run, Black Start, and Load Shed Service for Imports. The procurement is done by online trading for Operating Reserves and bilateral contracts for the other services.

Further details on the operation of these markets are outlined elsewhere as referenced throughout this report, and specifically in section2.2. For the purposes of this study, it is assumed that ES will be able to participate in all three markets - wholesale, ancillary, and a hypothetical capacity market, which was contemplated at the time of this study but is no longer being planned.

1.2.1.6 Transmission Topology Considerations

Alberta's transmission system is seen by the provincial government as an enabler to wholesale market operation as well as economic development in the province[18]. Under amendments to the *Electric Utilities Act* introduced in 2009, the Alberta Government designated "Critical Transmission Infrastructure" to be in the public interest (the ministerial power of designating Critical Transmission Infrastructure has since been repealed however). In short, the amendments provide an "uncongested transmission system" which is planned by the AESO and designated as a regulated monopoly service operated by transmission facility owners. This system connects approximately 26,000km of transmission assets with 235 generating units, and 200 market participants as of 2018. In this study, the full AIES electricity generation, transmission and load data were modelled as a fixed input. The grid model includes all existing assets above 69 KV, and a list of transmission facilities additions/retirements, and

[18] http://sites.ieee.org/pes-resource-center/files/2014/02/PESGM2006P-001239.pdf

anticipated transmission facilities already under planning or development were taken as fixed inputs to the study given the policy surrounding transmission development in Alberta. The use of these data ensures that an accurate topology and thermal limits of the AIES transmission system are reflected in this analysis, and in many cases is already publicly available including the most recent Long Term Outlook Report[19].

As outlined in section 1.2.2 below, several potential benefits of implementing ES relate to the ability to defer or reduce transmission infrastructure upgrades, therefore specific transmission deferral analysis was performed as per section 1.3 with input from the advisory board. Although not comprehensive, this provides an initial indication of the potential benefits of ES for transmission deferral.

1.2.2 ES Benefit Categories and Potential Use Cases

It is well understood that ES may provide a variety of services to the grid depending on how it is designed and operated. However, there is uncertainty as to which services are more or less valuable, especially considering the differing values to the regulator, utility, project developer, or end customer. While some benefits offered by ES projects are not currently monetized in the Alberta market framework outlined in section 1.2.1.5 above, in many cases they exist in other electricity market frameworks in the U.S. and internationally. In this study, where not currently monetizable under Alberta market frameworks, the other benefits are outlined to help understand the potential cost savings or other system-wide benefits of implementing storage on the AIES.

Unfortunately, the definitions of the values of storage vary from analysis to analysis, and market to market. Given that one of the goals of this study is to create a uniform understanding of the potential value of storage in Canada, it is therefore important to ensure that there is consistency in the understanding and definitions of the various use cases or benefits that storage might provide. In this study, benefits are assessed and presented in six categories. Table 1-1 identifies the ES use cases that are included in each benefit category. A detailed description of each use case follows the table.

Table 1-1: List of grid benefit categories and ES use cases considered in this study

Benefit Category	Formula and Description	Included ES Use Cases
Generation Cost Reduction	By utilizing ES for the services described in this category, the overall cost of generation is reduced. This happens not at the ES site, but through the overall system-wide benefits that operation of ES has on the other generation facilities on the grid due to its ability to optimize the operation of these other facilities. This can be seen in a grid-wide reduction in costs related to: fuel for existing plants, variable operations and maintenance costs of other generators, and startup and shutdown costs of the generation fleet. Since these benefits are related to the optimization of existing assets, they have been combined into a single benefit category. ***Calculated as the difference in total cost to generate required energy to meet demand***	• Load Following (1.2.2.2) • Increased Renewable Integration (1.2.2.9) • Energy Arbitrage (1.2.2.12)

[19] AESO 2017 LTO

	between the Benchmark and ES Capacity Scenario outputs	
Regulation and Spinning Reserve Cost Savings	The system operator must maintain a certain level of contingency reserve capacity to ensure the reliability of the grid, including spinning and non-spinning reserve. They also procure a certain amount of black start capabilities from qualified generating facilities to restore the operation of the grid in the event of a regional or system blackout. Additionally, if operated optimally, ES can be used to store energy to be used in the event that the system needs to be restored. Since these two services are generally contracted separately from generation capacity, they are included in a single benefit category. ***Calculated as the difference in total cost due to dispatch profile of generation between Benchmark and ES Capacity Scenario outputs. Black start cost assumed to be $0.3/kW***	• Reserve Capacity (1.2.2.4) • Black Start and System Restoration (1.2.2.6)
Frequency Response Cost Savings	In a power system, the balance between generation and demand is not instantaneous. The System Operator must maintain a certain level of operating reserve for frequency response to provide the instantaneous power difference between generation and demand. Some fast-response ES technologies, such as lithium-ion batteries and fly wheel storage, are ideal for providing frequency response to the grid. The use of ES to provide frequency response may reduce the total volume of required reserves and therefore reduce the cost to consumers. ***Calculated using the assumed factor of 50% of the total ES potential that is capable of providing frequency response service, which is estimated to cost $250,000/MW***	• Frequency Regulation (1.2.2.3)
Peaking Plant Capital Savings	It is possible to utilize ES to more effectively manage the peak demand of the power system by storing energy during off peak times, and transferring this capacity to on-peak periods. This allows less overall capacity to be built on the system, specifically peaking plants. This differs from generation cost reduction as it targets capital investments as opposed to operational expenditures. ***Calculated as reduced peak demand multiplied by peaking plant capital cost, which is assumed to be $1200/kW***	• Energy Supply Adequacy (1.2.2.1) • Energy Arbitrage (1.2.2.12)

Transmission and Distribution Cost Reduction	By strategically developing ES as "non-wires" alternatives to traditional infrastructure investments, it is possible to strengthen the electricity grid and create an overall more robust system. To do so, ES must be deployed at specific locations on the power system and provide a range of services that would be lower in cost to these traditional investments. This could create cost reductions that are either temporary (i.e., delay or defer infrastructure investments) or be more permanent solutions in areas where transmission or distribution infrastructure is adequate once peak loads are removed. ***Calculated using assumed transmission and distribution costs of $3.4/kW, and 100% of ES potential contributes to some form of transmission and distribution avoidance***	• Voltage Support (1.2.2.5) • Infrastructure Upgrade Deferral (1.2.2.7) • Transmission Congestion Management (1.2.2.8) • Black Start and System Restoration (1.2.2.6)
Distribution Value	The first four categories consider the overall value of ES at the generation and transmission levels. However, these same issues occur at a distribution level as well. The value of ES accrues to different parties when at the distribution level, and therefore must be considered as a separate category. ***Calculated using assumed factor of 30% of ES benefits that can be realized at the distribution level, and applying a discount rate year over year from the first ES in service date***	• Load Following (1.2.2.2) • Renewable Integration (1.2.2.9) • Power Quality and Reliability (1.2.2.10) • Demand Charge Management (1.2.2.11) • Energy Arbitrage (1.2.2.12)

To facilitate comparison with other ES studies, details on each ES use case are provided below.

1.2.2.1 Energy Supply Adequacy

The AESO supply adequacy, based on peak demand of the grid plus reserve margin, represents the power systems' ability to meet demand in the long run, taking into consideration the regular day-to-day and season-to-season fluctuation and uncertainty in demand and supply. The issues for supply adequacy planning are mainly due to errors in forecasted demand growth and extended periods of unexpected generation facility outages. This often results in capital investment loss on generation assets, over or under planning of transmission and distribution infrastructures, and supply shortfall or surplus situations. Without some type of storage, it is not possible to time-shift energy generated at one point in time and release that stored energy at another point in time.

The ability of ES to time-shift the stored energy makes it a potential solution (subject to ISO rules) for supply adequacy planning purposes. With the adequate amount of ES system capacity being considered during the supply adequacy planning process, it can increase the utilization rate of generation assets and alleviate financial burdens on the power system.

1.2.2.2 Load Following

Load following is characterized by the power plant's generation output which may change as often as every few minutes in response to the changing demand within a control area. For a thermal power plant, cycling to follow load is less efficient than operating at a constant output level.

ES systems have a unique property that enables them to absorb energy as well as deliver it so they can discharge when demand increases and charge when demand decreases. ES systems can be used as standalone systems to provide load following services by absorbing and releasing the energy from and to the grid directly or can be implemented in association with generation units to provide load following service and increase overall power plant efficiency.

1.2.2.3 Frequency Regulation

Frequency regulation is a service that corrects for real-time momentary imbalances between generation and load that causes the frequency of the power system to deviate from its nominal value. If the imbalance is severe enough, this could result in cascaded generator tripping events and cause a network-wide failure leading to a system blackout.

The primary purpose of frequency regulation is to maintain grid stability and comply with the North American Electric Reliability Corporation's (NERC) BAL-001 (Real Power Balancing Control Performance) and BAL-002 (Disturbance Control Performance) standards. Traditionally, this is achieved by adjusting generator inertia, ramping generation assets up or down, and procuring dedicated demand response resources. Because ES can rapidly ramp its power output up and down, and act as a load, it is particularly well suited to being used as a regulating asset.

1.2.2.4 Reserve Capacity (Spinning, Non-Spinning/Supplemental)

In the event of an unexpected failure of a system component, such as a generating unit, transmission line, circuit breaker, switch, or electrical element, the spinning and supplemental reserves (collectively referred to as contingency reserves in some balancing authorities) are called on with short notice to provide capacity in order to correct any imbalance of supply and demand. In the case of supply shortfall, spinning and supplemental reserves will be directed to match the demand. Traditionally, the spinning and supplemental reserves can come from the supply side (generator) or from the demand side (load curtailment by reducing demand from large electrical consumers immediately). Energy storage systems can be utilized to provide spinning and supplemental reserve by charging or discharging on demand in compliance with ramp rate requirements in a balancing authority control area.

1.2.2.5 Voltage Support

System operators must ensure that the voltage on the transmission and distribution system is maintained within an acceptable range at all times to ensure power generation and demand are matched continuously, and to protect the power system equipment.

The voltage regulation and Volt Ampere Reactive (VAR) regulation (although there is no current market in Alberta for this) are required to maintain acceptable voltage and power factors along transmission lines and on the distribution feeders under all loading conditions. In Alberta, generators must provide voltage support. In addition to adjusting generator terminal voltage, switching capacitor banks, reactors, and load tap changers as well as dispatch static VAR compensators and line switching are all methods of regulating voltage.

The balancing authority in a control area must have sufficient reactive resources within its boundaries to provide voltage support in order to mitigate a NERC category B contingency violation (loss of single element). An ES system is well suited to provide distributed voltage/VAR support close to the point in the power system where it is needed.

1.2.2.6 Black Start and System Restoration

In the unlikely event of a system-wide blackout caused by a catastrophic failure of the grid, black start resources are used to re-energize a pre-defined transmission and distribution path (cranking path), and to provide startup power to generators that cannot self-start. In addition to the black start resources in the system today, ES systems can be utilized to provide startup power to the nearby generation facilities.

In the event of a regional black out, where "pockets" of black outs may be caused by less severe system outages, generation facilities with co-located ES systems can self-start and restore power to the regional grid, and distribution facilities with co-located ES systems could potentially avoid load loss.

1.2.2.7 Infrastructure Upgrade Deferral

ES systems can be utilized to delay or avoid entirely the utility investments in transmission and distribution system upgrades that are necessary to meet future demand growth on specific regions of the grid.

For example, it is an engineering best practice to evaluate potential load growth when replacing aging distribution transformers so a decision can be made on whether to replace a distribution transformer with a same rating new transformer or upgrade it to facilitate future demands. If the decision is to upgrade, this leads to an unavoidable result of new transformer underutilization for the first several years of its lifespan when the demands remain at similar levels as the current level. This underutilization period could be longer if the forecasted load growth does not happen at all. In situations where the forecasted load growth has high degrees of uncertainty, a cheaper, same rating new transformer could be used with an ES system to offload peak demands.

In addition, ES systems can be used to avoid distribution upgrades entirely if the need to upgrade is due to peak demands exceeding the load carrying capacity on the distribution system. Instead of upgrading the infrastructure, an ES system can be implemented to supply extra energy needed during peak hours.

Furthermore, in a bulk electric system with peak demand approaching its designed load carrying capacity, installing a relatively modest amount of ES downstream from the nearly overloaded transmission node could defer the need for the equipment upgrade for a few years. ES systems can be used to reduce loading on existing aging equipment in the bulk electric system, reducing wear on equipment and extending its life. This may be especially compelling for transformers and underground cables from a cost perspective.

Transmission and distribution upgrade deferral is highly location-specific. The value of deferral varies significantly depending on the condition and age of the system, the prevailing load profile, and load growth forecast.

1.2.2.8 Transmission Congestion Management

Transmission congestion happens when there is insufficient transmission capacity to deliver least-cost energy to some or all loads in a power system. The congestion is actually a shortage of transmission facilities to supply a waiting market. In a competitive electricity market, there is a risk of price gouging from utilities that control the generation assets. Regulatory bodies are aware of this risk and most jurisdictions have built safeguards into the market regulations to ensure that congestion-related energy cost increases reasonably reflect the additional costs incurred in alleviating the congestion condition. ES systems can be utilized to avoid congestion-related costs and charges by decreasing peak demand wherever transmission congestion may occur. In this use case, an ES system would be installed downstream from the congested area of the bulk electric system and would be charged when there is no congestion condition in the area. They would then supply energy to the power system during peak demand periods to reduce peak transmission capacity requirements.

1.2.2.9 Renewable Integration

The fast-growing renewable energy markets continue to be solar PV and wind power. These variable forms of generation may present challenges to the power system, which was designed using a centralized model with predictable power flows at very high penetration levels. As the total amount of solar PV and wind power generation in a control area increases, this variable generation source can require other generators to increase ramp rates. However, this growing variable generation source also presents opportunities for an ES system. An ES system's ability to "smooth" the variable power from solar PV and manage ramp rates from wind to the grid could potentially reduce the system operators' challenge on renewable integration. System operators typically manage all variable generation collectively as a negative load and look purely at the "net load". Solar PV has a high correlation with Alberta's load, whereas wind power has a lower correlation with load.

1.2.2.10 Power Quality and Reliability

The quality of electric power is often described as the power grid's ability to supply a clean and stable power source to the end customers. In other words, a power source with ideal power quality is a perfect power supply that is always available, has a pure noise-free sinusoidal wave shape, and is always within voltage and frequency tolerances. However, with increasing and varying energy demands from various industrial processes, many loads regularly create disturbances on the power grid, making deviations from these ideal conditions frequent.

ES systems can be utilized for enhancing power quality against short-duration events that affect the quality of power delivered to the customer's loads. For example, an ES system can be used to regulate voltage deviation and frequency deviation. They can also be used to perform power factor correction and harmonics reduction.

Power reliability refers to the power that is available when needed. Outages, whether momentary or sustained, usually cause service disruption to customers, and for commercial and industrial users, the economic consequences can be significant. ES can be utilized to provide auxiliary power to customers when there is a total loss of power from the utility grid. This effectively "islands" the customer load from the grid and resynchronizes when power is restored from the utility.

1.2.2.11 Demand Charge Management

Demand charge is a method that utilities use to charge customers based on the energy required for a short period of time, typically a 15-minute interval. In some markets, this concept is translated into a time-of-use energy rate, where utility customers get charged different kWh rates for the energy consumed during peak and non-peak hours. Depending on the utility and rate structure, demand charges can account for over half of a commercial customer's monthly electricity costs. Furthermore, demand charges currently exist for some residential customers, and a growing number of utilities are considering implementing residential demand charges in order to curb annual peak electricity demand growth. Utility customers can utilize ES systems to effectively reduce their peak-hour electricity consumption and therefore reduce or avoid demand charges in the electricity market.

1.2.2.12 Energy Arbitrage

In a deregulated electricity market, with hour-to-hour changes in the wholesale electricity price, an ES system can be utilized for energy arbitrage purposes. ES system owners can purchase electricity during periods where prices are low, store it, and sell it back to the grid at times when prices are high.

1.2.3 Referenced Studies and Analyses

To learn from and leverage previous ES planning and/or road mapping activities, and to ensure an accurate interpretation of reasonable assumptions are used in the study, a large number of previous reports and methodologies were reviewed, both within Canada and internationally. A brief summary of the more relevant and recent studies that were referenced heavily for information and data is listed below.

- **State of Charge: A Comprehensive Study of Energy Storage in Massachusetts**[20]
  This study was completed and a report was compiled by Alevo Analytics, the predecessor of Acelerex Consulting. It is a Massachusetts-focused, stakeholder driven, co-optimization study in which regulatory entities projected ES deployments that were considered as inputs to the study model, and the results of the anticipated benefits and challenges are simulated as the outputs.

- **Regional Electricity Cooperation and Strategic Infrastructure Initiative (RECSI)**[21]
  This study was funded by Natural Resources Canada’s Energy Innovation Program and was aimed at evaluating and ranking the most promising electricity infrastructure projects in the four western provinces of Canada. The study was facilitated by AESO and conducted by General Electric. The output demonstrated that transmission-connected bulk ES projects do offer comparative financial structure and grid reliability benefits to those major transmission facility projects.[22]

- **Energy Storage in Alberta and Renewable Energy Generation**[23]
  This study was conducted by Solas Energy Consulting Inc. under contract with Alberta Innovates and ERA. It analyzed the impact of ES to the AIES on the individual project level and was primarily aimed at evaluating the effects of ES on GHG emissions in Alberta.

1.3 Pillar 1 Methodology

Given the complexity of the market, the various benefits that might be attributed to storage, and the rapidly changing technological landscape described in section 1.2 above, it is not surprising that a more comprehensive analysis of the potential for ES within the Alberta marketplace has not been completed. Most studies reviewed in preparation for this work and outlined in section 1.2.3 generally follow either a project-specific or case-based analysis methodology. In this study, it was determined that a broader analysis of the potential benefits of storage, that was as independent as possible of the influences of specific technologies, existing infrastructure,

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[20] https://www.mass.gov/files/documents/2016/09/oy/state-of-charge-report.pdf

[21] http://publications.gc.ca/site/eng/9.859802/publication.html

[22] **https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/clean/RECSI_WR-SPM_eng.pdf** - **Table 1.** RECSI project GHG emissions reductions and costs, project of option A1, A2 and F1

[23] https://albertainnovates.ca/funding-clean-technology/energy-storage/

existing planning assumptions, or policies, would be optimum to first determine the overall benefits that the AIES might see by adopting storage. This does not necessarily mean that the results of this pillar should be taken independently, or without review of specific project feasibility, but rather as a starting point for further analysis of the options presented. With this approach, it is expected that some of the potential system-wide benefits of adopting ES will be identified and can be incorporated in future grid planning and policy decisions moving forward.

For Pillar 1 of this study, a large, grid-level simulation was completed using a co-optimization approach as shown in Figure 1-2 that performs steady-state power flow, capacity optimization and production cost optimization. This approach differs from existing studies in that the simulator was able to "freely" place ES at any nodes in the model subject to power system stability where it could provide the benefits described in section 1.3 above. This approach also allows the model to generate outputs for the optimum location, size, type, and operational date for ES projects that could be built in future deployments, as well as the overall benefits that the grid might receive from doing so with respect to incumbent technology options free of unnecessary constraints.

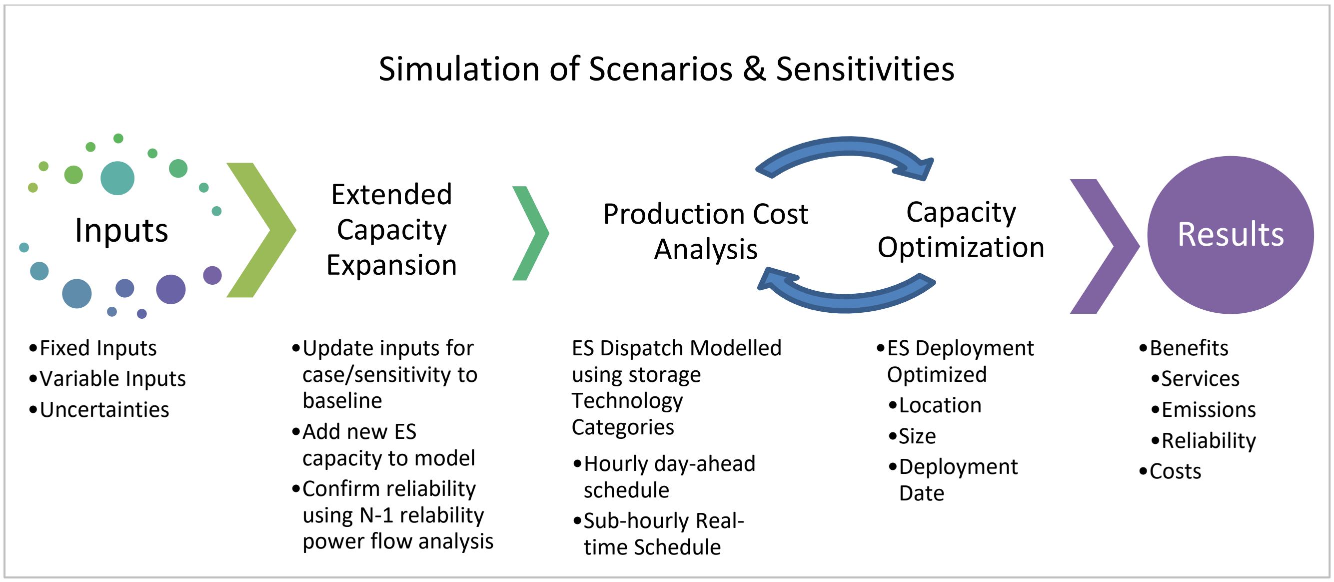

Figure 1-2: Grid-level ES analysis methodology

As with all models, the results are only as useful as the accuracy of the methodology utilized, as well as that of the inputs and assumptions. In this study, the model was built based on the historical data as published in the AESO's 2017 LTO data file, and grid topology information obtained from AESO 2017 planning base case suites. In addition, inputs into the model included the most recent data files for the following:

- Demand forecast
- Fuel price forecast
- Generator additions and deactivations
- Transmission flows and constraints
- Future renewable expansions
- Firm additions and retirements of grid elements
- Flows on the inter-ties according to the U.S. border equivalent model
- Technology costs, including levelized cost of storage

Due to the complexity and importance of the various inputs to the model, further details on the specific inputs and assumptions to the model are provided in section 1.4.1 below.

Once the model was built, it was used to run a number of cases to address specific future planning scenarios and input data sensitivities. In order to ensure the accuracy of the analysis, the 2017 AESO LTO was used as a baseline. From there, a re-optimized base case was developed which added optimized storage across the network. Finally, several sensitivity analyses were performed in order to determine how various factors might affect the outcome of the study, both in direction and magnitude. Further details on the specific cases and their related assumptions are provided in section 1.3.2 below.

Finally, within each case, the model was run using three stages of analysis which allow for a co-optimization of capacity and benefits. This optimization was run on a supercomputer to allow the analysis of each grid node, technology type, size, build date, and dispatch type to be considered independently. The eventual result of the millions of data points analyzed is an optimized lowest-cost solution for the entire AIES system, where the benefits of any single storage project suggested is larger than the cost of build out, or of traditional assets on the grid.

1.3.1 Model Operation

As described above, the model utilizes a co-optimization approach to reduce costs and increase the benefits to the network. In order to complete this while minimizing the computational effort required to do this optimization, it is important to separate the analysis into stages, where refinements are made to the parameters and increasing detail is added to the simulation itself. These steps are outlined below.

1.3.1.1 Simulation Stage 1: "Extended" Capacity Expansion

The capacity expansion is termed "extended" because it considers storage as a capacity candidate that is incremental to the AESO LTO. At this stage, for simplicity, a single capital cost (an average of the four categories provided in Table 1-2 below) is assumed for the capacity of ES built, regardless of the type of storage. The model evaluates the need for ES systems located within the grid without at first considering the energy-limited nature of ES. This simplification is intended to increase the computational efficiency of the first step and enables the optimizer to evaluate whether the existing generation capacity is adequate at each node for the forecasted demand within the study horizon. If not, the optimizer then determines the required capacity at each node in order to meet demand. Optimizations to this added capacity at this stage select the nodes and the sizes of storage that minimize the investment costs and maximize the benefits over the study period. This stage uses low resolution planning data/seasonal data to perform power flow studies as ES is added to the model to ensure no contingency issue will occur in the system during extreme conditions (i.e. winter peak, summer peak, etc.) where stage 3 (described below) utilizes high resolution data, output from stage 2, which provide hourly and sub-hourly dispatch of the ES along with all available generations in the system to optimize the utilization of ES.

Specific limitations are built into the model to constrain the following:

- Energy Balance – Additional ES capacity is added based on estimated demand growth and anticipated generation additions and retirements[24]

[24] AESO 2017 LTO and LTP

- Reliability – Additional ES capacity is added that complies with all thermal constraints in the existing and approved future transmission system, focusing on 240kV and above.

1.3.1.2 Simulation Stage 2: Production Cost Analysis

In the model operation, once the initial capacity is added, a production cost analysis is completed, again without a duration limit, in order to determine the following:

- The amount of energy that should be supplied at the proposed nodes in order to minimize operational and capital costs over the study period.
- Initial dispatch and service provisions on an hourly and sub-hourly basis. This chronological optimization provides the initial benefit estimates.

1.3.1.3 Simulation Stage 3: Capacity Optimization

Finally, a capacity optimization phase takes and inputs capital costs and operational costs of current and future assets to run the grid, as well as new technologies, and performs a least-cost minimization analysis. In the capacity optimization phase, the MW size and location of ES systems are determined. The objective function of the capacity optimization modeling is to minimize the production cost and the capital cost of the system. The optimization is accomplished by minimizing a number of parameters, according to the following formulation.

$$\min_x \Big(\sum_i a_i P_i + \sum_{i,t} \Delta_t g_{i,t} c_i + \sum_{ee} a_{ee} P_{ee} + \sum_d a_d P_d + \sum_{d,t} \Delta_t \big(d^+_{d,t} + d^-_{d,t}\big) c_d + \sum_r a_r P_r + \sum_s a_s P_s + \sum_s a_{es} E_{s,max} + \sum_{s,t} \Delta_t \big(g^+_{s,t} + g^-_{s,t}\big) c_s \Big)$$ [25]

Where:

$\boldsymbol{a_i P_i}$	*Capital costs of peaking generators*
$\boldsymbol{\Delta_t g_{i,t} c_i}$	*Variable costs of peaking generators*
$\boldsymbol{a_{ee} P_{ee}}$	*Investments in energy efficiency*
$\boldsymbol{a_d P_d}$	*Investments in demand response*
$\boldsymbol{\Delta_t (d^+_{d,t} + d^-_{d,t}) c_d}$	*Variable demand response costs*
$\boldsymbol{a_r P_r}$	*Investments in VER*
$\boldsymbol{a_s P_s}$	*Investments in ESS for power capacity*
$\boldsymbol{a_{es} E_{s,max}}$	*Variable costs of ESS for energy capacity*
$\boldsymbol{\Delta_t (g^+_{s,t} + g^-_{s,t}) c_s}$	*Variable costs of ESS for power output*

Based on this approach, three detail levels of capacity optimization are then completed:

- **Annual Optimization** - The annual optimization is performed over each year of the study horizon and decomposes monthly generation profiles as well as enforces any annual constraints such as emission constraints.
- **Hourly Production Cost Optimization** - The hourly production cost phase simulates day-ahead dispatch schedules and optimizes the system variable costs of current assets along with future assets and

[25] Acelerex applied production cost optimization methodology

optimizes the MWh of ES from the capacity optimization phase. The hourly production cost is a nodal model that enforces N-1 contingency criteria.

- **Sub-Hourly Production Cost Optimization** - The sub-hourly production cost phase simulates real-time dispatch schedules and optimizes the system variable costs of the current assets along with future assets, and refines the sizing of ES in terms of MW and MWh.

These results are then presented as the output of the model.

1.3.2 Benchmark, Scenarios, and Sensitivities

As described above, the model is run for each case that includes a fixed set of assumptions. These are important to consider individually as the assumptions may be contradictory or not possible to consider within a single optimization. For the purposes of this analysis, several different cases were run. These included a benchmark case, two different scenarios, and two parametric sensitivity analyses. The cases are shown in detail in Figure 1-3 below.

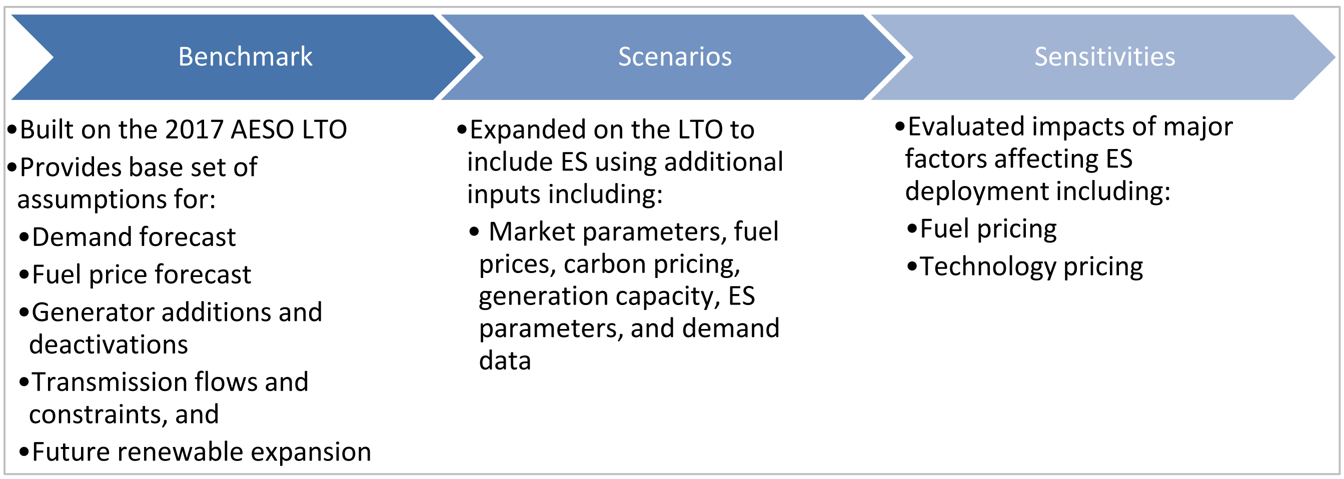

Figure 1-3: Pillar 1 simulation cases

For this study, the six cases modelled, including the transmission deferral capability review, were the following:

- Benchmark (performed for validation):
  - This scenario was developed based on the "reference" case from the AESO 2017 LTO report in consideration with the key aspects discussed in section 1.2. This case was used in order to maintain consistency with publicly available scenarios.
- Scenarios:
  - Case #1: *ES Capacity Scenario* – This re-optimized scenario extends the benchmark to include ES as described elsewhere in this document. No specific modifications to grid topology were considered.
  - Case #2: *Transmission Deferral Scenario* – This re-optimized scenario modifies the benchmark to specifically look at the ability of storage to lessen the cost of infrastructure investments. This is considered separately from the ES capacity scenario as it required a modification of the underlying grid model that was used in the analysis. The scenario considered also aligns with the work completed in the recent NRCan/AIES RECSI study reviewed in section 1.2.3.
- Sensitivities:

- *Fuel Pricing* - The prices of various fuels (gas, coal, biomass, wood) were varied by 40% on each side of current average prices to determine the impact fuel pricing may have on the overall assumptions/outcomes of the study. The values of 40% were chosen for consistency with historical fuel price variations.
    - Case #3: +40% fuel price
    - Case #4: -40% fuel price
- *Technology Cost* – It is clear that the costs of storage have varied greatly over the past 10 years, and are expected to change further over the study period. Therefore, an ES Technology Capital Cost sensitivity was completed which utilized a 40% variance on each side of the applied levelized cost of storage. The value of 40% was chosen based on stakeholder feedback and benchmarking technology cost reviews.
    - Case #5: +40% technology capital cost
        - To account for the higher costs for various ES technologies in the same technology category
        - To evaluate the potential impacts from future material shortages for certain ES technologies, stricter environmental requirements on ES technologies, etc.
    - Case #6: -40% technology capital cost
        - To account for the lower costs for various ES technologies in the same technology category

1.4 Summary of Inputs and Assumptions

As described above, the accuracy of the inputs and assumptions used in the analysis is critical to generate meaningful outputs. It is important therefore to differentiate between those values which are fixed inputs, which are variable inputs/parameters, and which are outputs.

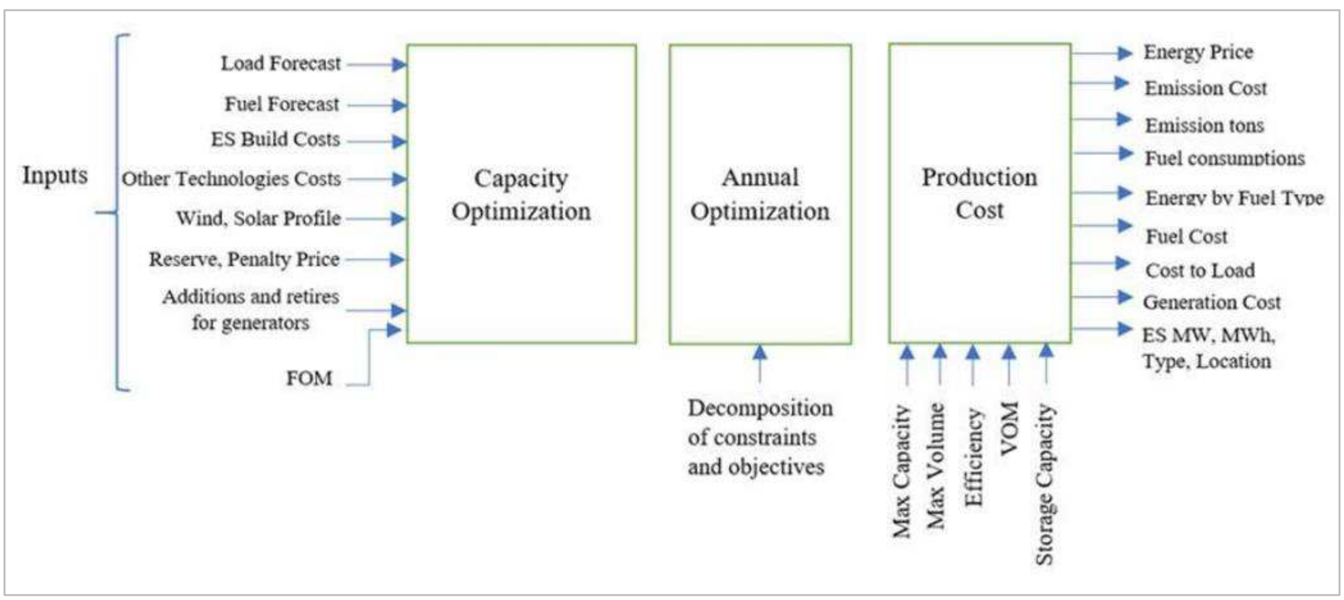

Figure 1-4: Example model inputs and outputs[26] of the simulation tool used in all three of the simulation stages

[26] Data flow in Acelerex Production Cost Optimization model

Further detail on each of the inputs, including how they are treated in the study are provided below.

1.4.1 Inputs and Assumptions to the Model

The following inputs and assumptions to the model were used across all cases based on input from the advisory board and other stakeholders. Wherever possible, the specific sources of the assumptions or data are listed in each section to allow the reader to validate the assumptions and/or modify their own analysis based on data presented or future changes that are outside the scope of this study.

1.4.1.1 Alberta Market Structure

The Alberta market, including policy and operational requirements, was outlined in section 1.2. This information was then compiled and entered into the model using the following inputs and assumptions. These were included as fixed inputs as they can be considered to be constant barring changes in policy that are outside the scope of this study. In many cases these values are the outputs of other, less ES-focused analyses. They simplify the overall number of cases studied and can be re-run as required when specific values or policies change. Specific market-related inputs or assumptions used in the model include the following:

- The Peak Internal Load in Alberta increases from 11,473MW in 2017[27] to 13,486MW by 2032.
- The Internal Energy Load in Alberta increases from 82,572GWh in 2017 to 94,304GWh by 2030.
- The incremental wind power generation provided by the AESO is treated as a firm addition to the model, and the anticipated coal-fired generation facilities retirement schedule is respected with firm retirement dates. In order to account for the coal-fired generation facility fuel-type conversion, the simulator decommissions the existing facility and evaluates if a new gas-fired generation facility is required in the Alberta grid. If deploying ES to the AIES is more beneficial financially, and offers equivalent grid reliability, the coal-fired generation facility conversion is considered unnecessary and a new gas-fired generation facility is not built.
- Generation Capacity:
    - Approximately 6299MW of coal-fired power generation will go offline by 2030 due to policy changes, the Climate Leadership Plan, and Federal Coal Regulations[28].
    - Approximately 4728MW of combined-cycle, simple-cycle, and cogeneration capacity will come online, including conversions of coal-fired plants to gas fired facilities, by 2032 to compensate for the coal-fired power generation retirement and to facilitate renewable generation additions in the province.[29]
    - Approximately 5,000MW of new wind power generation is expected by the AESO under the AESO 2017 LTO to come online by 2032 due to the regulatory requirement to achieve 30% of energy from renewable sources by 2030 (provincial Renewable Electricity Program and Climate Leadership Plan).
    - Approximately 700MW of new solar power generation is expected by the AESO under the AESO 2017 LTO to come online by 2032 due to the regulatory requirement to achieve 30% of energy

[27] AESO, 2017 LTO and 2017 Annual Market Statistics.

[28] "Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations," April 24, 2018, http://laws-lois.justice.gc.ca/PDF/SOR-2012-167.pdf.

[29] AESO 2016 Planning Base Case Suite files

from renewable sources by 2030 (provincial Renewable Electricity Program and Climate Leadership Plan).

1.4.1.2 Carbon Pricing

For electricity generators, a performance standard carbon price for Large Final Emitters was introduced in the 2016 provincial budget[30]:

- \$20 CAD/tonne CO_2e in 2017, and
- \$30 CAD/tonne CO_2e from January 1, 2018 onward.

As described in section 1.2.1.4, the carbon price in the model was maintained at a fixed value (\$30 CAD/tonne CO_2e).

1.4.1.3 Generation Capacity Factors

The capacity factors used for the various fuel types and generators in the model were fixed. However, given the importance of these factors, the details of these assumptions are provided below:

- For the initial year of the study period (2017), capacity factors were calibrated to historically observed values as per the AESO dataset.
- For the remainder of the study period (up to 2030), the capacity factors were determined by the model and depend on technology-type capabilities, resource, market conditions and expected major changes over the study period (e.g. coal power retirement schedule).
- For wind power generation (built after 2019):
  - Expected capacity factor increases compared to historical figures as newer turbine technology are rated at ~4MW with higher hub heights, larger rotor diameter, and up to a 48% capacity factor compared to current turbine hub heights and rotor diameter.
  - As the current Alberta electricity market requires that wind power generation is utilized when available, barring reliability constraints, it is expected that the capacity factor for wind power generation will be at a level of 40% or higher.
- For other fuel types, the only constraints are market dynamics[31] as determined by the model.

1.4.1.4 Generator Heat Curves

Generator heat curves are assumed to be linear to reduce modelling complexity. This assumption underestimates the value of storage in most cases as it reduces its ability to perform ideal generator cost reduction through increased traditional generation efficiency improvements.

1.4.1.5 ES System Operating Parameters

The following parameters are specific to the operating parameters and maintenance requirements of ES:

- The average round-trip-efficiency value used in the model for all ES technologies is assumed to be 88%.
- Variable operations and maintenance costs (VO&M) are assumed to be zero in the model because these costs in actual systems are understood to be minimal, and assigning them a value of zero reduces the complexity of the simulation run.
- For each ES technology category, the capital costs, technical lifetime, and economic lifetime values are shown in Appendix III.

[30] http://finance.alberta.ca/publications/budget/budget2016/fiscal-plan-complete.pdf%20page%2093

[31] https://www.aeso.ca/download/listedfiles/How-is-the-Pool-Price-for-Electricity-Determined3.pdf

- Additional Alberta-specific costs (DTS and STS) are used for ES charging and discharging, on top of pool prices. This is discussed in more detail in section 2.5.3.

1.4.1.6 Technology Options

The methodology used for this pillar is designed to allow an ES technology-agnostic approach. However, it is clear that ES operates differently, with differing capabilities that can provide specific services/performance depending on technology, design, and dispatch. Therefore, instead of utilizing very specific types of storage, four broad categories corresponding to the power/energy balance of a specific installation were used. For each technology category, representative technologies were utilized to define the operational capacity (in terms of hours of duration at full power) of each technology category, along with representative technology capital costs for the blend of technologies described in the examples. The categories, capacities, and technology examples utilized are shown in Table 1-2 below.

Table 1-2: Storage Technology Categories

Storage Technology Category[32]	Duration at Full Power	Examples
Long Duration	4+ Hours	CAES, Flow Battery, NaS Battery
Medium-Long Duration	2 Hours	Lithium-ion, Flow Battery, NaS Battery, NaNiCL2 Battery, Advanced Lead Acid
Medium-Short Duration	1 Hour	Lead Acid, Lithium-ion, NiCd, NiMH
Short Duration	30 Minutes	Lithium-ion, Flywheel, High Power Super Capacitors, Thermal Storage

1.4.1.7 Fuel Prices

Due to the uncertainties in fuel availability and costs, a fuel price sensitivity study was completed for the Alberta analysis. Daily Natural Gas 2015-2016 data[33] were used as the historical natural gas price, and the monthly AESO 2017 LTO gas price forecast was used as the natural gas forecast price. The fuel price has an impact on variable operation and maintenance costs of the generation fleets, and therefore has a potential impact on the deployment sizing and timing of ES in the bulk electric system.

Alberta does have biomass/wood generation (see Electricity Capacity and Primary Fuel Sources in Appendix IV). The coal, biomass and wood fuel prices used were provided by Acelerex Consulting. When available, Canadian prices were used, otherwise international prices were used (and converted to CAD) that conform to prices used in comparable studies. This study assumed that biomass and wood fuel prices will remain constant throughout the entire time period because there is uncertainty as to future trends in these fuel prices.

The fuel prices used in this study are summarized below in Table 1-3, collected from the sources mentioned above.

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[32] Categorizations developed by Acelerex and utilized in their modeling tool

[33] NGX daily prices http://www.ngx.com/?page_id=644.

Table 1-3: Fuel Price Summary

Annual Av. Price (Cd$/GJ)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NG	4.40	4.59	4.67	4.82	4.72	4.57	4.70	4.80	5.13	5.04	5.11	5.50	5.53	5.50
Coal	4.35	4.46	4.40	4.52	4.49	4.37	4.49	4.49	4.36	4.36	4.36	4.36	4.36	4.36
Biomass	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29
Wood	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27

1.4.1.8 Load Demand

This study used energy and peak load measures based on the Alberta Internal Load (AIL), which includes load served by behind-the-fence generation. AESO Hourly Load Data for 2016 was used as the historical load profile and the annual peak load and energy data from 2017 LTO data file for 2017-2030 as the forecast load and energy profile.

Table 1-4: Forecast Load and Energy Profile

Demand	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Load (MW)	11,539	11,737	11,939	12,018	12,144	12,260	12,321	12,428	12,557	12,678	12,814	12,945	13,089	13,231
Energy (GWh)	82,607	83,884	85,467	87,142	87,710	88,287	88,668	89,639	90,354	91,092	92,097	93,124	93,804	94,719

1.4.1.9 Initial Generation Capacity

Generation capacity by fuel type from the 2017 LTO was used to build the generator installed capacity inside the model. The model includes three step changes for new generator capacity in years 2017, 2022 and 2027, resulting in a significant decrease in the use of coal-fired generators and a large increase in clean energy generators usage. The study considered these "anchor years" from the AESO's 2017 LTO[34] and interpolated (linearly) the values for the years in between (not provided in the 2017 LTO), up to the study's final year (2030).

Table 1-5 shows the generator installed capacity by type for 2017 to 2030 inside the model. The data are interpolated by the model from the LTO 5-year capacity forecast data, and wind capacity data from CanWEA and the Alberta WindVision Technical Overview Report are added to generate annual values for each year of the time horizon.

Table 1-5: Generator Installed Capacity

Capacity (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	6299	6299	6299	5405	4618	3824	3059	3059	3059	2904	2904	2904	1239	0
Cogeneration	4934	4952	4970	4988	5006	5024	5042	5060	5077	5095	5114	5132	5150	5168

[34] https://www.aeso.ca/grid/forecasting/

Combined Cycle	1746	1746	1746	1746	1746	1746	1928	2110	2292	2474	2656	3202	3748	4294
Simple Cycle	917	945	972	1001	1008	1059	1097	1135	1173	1211	1249	1296	1343	1390
Coal-to-Gas	0	0	0	25	812	1606	2371	2371	2371	2371	2371	2371	2371	2371
Hydro	894	894	894	894	894	894	894	894	894	894	894	964	1034	1104
Wind	1445	1765	2085	2405	2725	3045	3445	3845	4246	4646	5045	5325	5605	5885
Solar	0	40	80	120	160	200	240	280	320	360	400	400	400	580
Other	479	479	479	479	479	479	479	479	479	479	479	479	479	479
Installed Capacity	**16,714**	**17,120**	**17,525**	**17,063**	**17,448**	**17,877**	**18,555**	**19,233**	**19,911**	**20,434**	**21,112**	**22,073**	**21,369**	**21,271**

1.4.1.10 Renewable Energy Generation

The study used the transmission system capability based on the 2016 planning base case suite and current and anticipated renewable generation from AESO 2017 Long-term Transmission Plan file to find the locations for existing and future wind and solar generators inside the model (see details in Appendix II). The renewable energy generation capacity and locations in the model are used to determine optimal sizing and locations of ES deployment.

1.4.1.11 Grid Topology

The topology used in the model is based on the 2016 planning base case suite. The study takes into consideration the thermal limits on transmission lines 240kV and above. This is to ensure that adding ES to the grid at any given node in the topology will not cause transmission constraints.

1.5 Simulation Results

The Pillar 1 results from the simulations for the various cases (baseline, scenarios, and sensitivities) are presented in detail below. Comparisons and observations of the results are also presented.

1.5.1 Benchmark Simulation

The benchmark simulation was calibrated to the 2017 AESO LTO “reference” case, and is the benchmark against which the other scenarios and sensitivities are compared.

1.5.2 Case 1: ES Capacity Scenario

For the 2017 - 2030 study years, the model included 100 electric nodes in the AIES topology with the potential for ES deployment. Detailed information regarding the exact location and amount of storage at each node is provided in Appendix I**.** It is not expected that ES systems would be built in every location, but rather that those locations that are the most feasible for supporting ES system projects. In the case where multiple nodes are close together, there is the potential of aggregating multiple smaller ES systems which may produce greater benefits from the grid reliability perspective. Conversely, it is possible to disaggregate a transmission-connected ES system into distribution connected distributed ES systems. However, this will be evaluated separately when a potential project is identified by market participants, system operators, or investors. The potential ES capacity is presented according to the four categories adopted in our methodology and deployment year.

The model estimates a total of 1,152MW installed by 2030. The timeline showing the amounts and years in which the ES systems are deployed in the ES Capacity scenario is shown in Table 1-6. As can be seen, most of the ES capacity is optimally deployed from 2027 to 2030 due to predicted technology price reductions, and provincial mandates for carbon pricing and coal retirements, except for 75MW short duration technologies which would optimally be deployed in 2024.

Table 1-6: Deployment timeline for potential ES facilities (Benchmark Simulation)

ES Capacity Scenario									
Deployment Category	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Capacity (MW)**
L	--	--	--	--	--	--	--	781	781
ML	--	--	--	--	--	--	67	4	71
MS	--	--	--	--	28	--	197	--	225
S	--	75	--	--	--	--	--	--	75
ES Capacity Total	**--**	**75**	**--**	**--**	**28**	**--**	**264**	**785**	**1152**

The power and energy characteristics of these stations are 1152MW and 5458MWh, respectively. The distribution of ES within the four storage technology categories used in this study representing the total dispatch of all potential ES in the grid throughout the study horizon is shown in Figure 1-5 below.

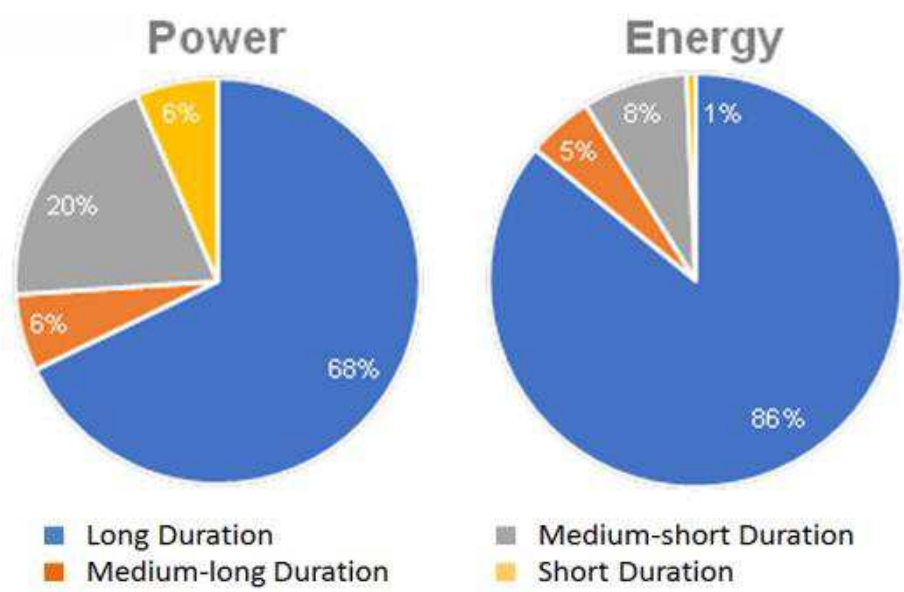


Figure 1-5: Power/Energy distribution by storage technology category (ES Capacity Scenario)

In looking at trends during the overall study period, it can be seen that as ES technology costs reduce, longer duration ES systems will become economical to be deployed towards the end of the study period. The study output also indicates that more opportunities for ES systems emerge towards the end of the study period.

1.5.2.1 Impact of ES on Electricity Prices

The study also evaluated the effect of the addition of ES to the Alberta electricity grid on electricity prices. Figure 1-6 shows the annual average electricity price in Alberta throughout the study period with and without ES.

As can be seen in Figure 1-6, when the potential ES determined by the analysis (1152MW) is deployed, the electricity price varies between $42.8 and $51.5/MWh over the study period (2017-2030). The electricity price differential is negligible until the final year of the study horizon when sufficient ES is added (785MW added in 2030) to have a positive impact on reducing the electricity price. The potential reason for this price reduction is that once the installed capacity of ES reaches a significant amount, it can effectively reduce peak demand, and as more and more renewables are integrated into AIES, the charging cost for ES could also potentially be minimized.

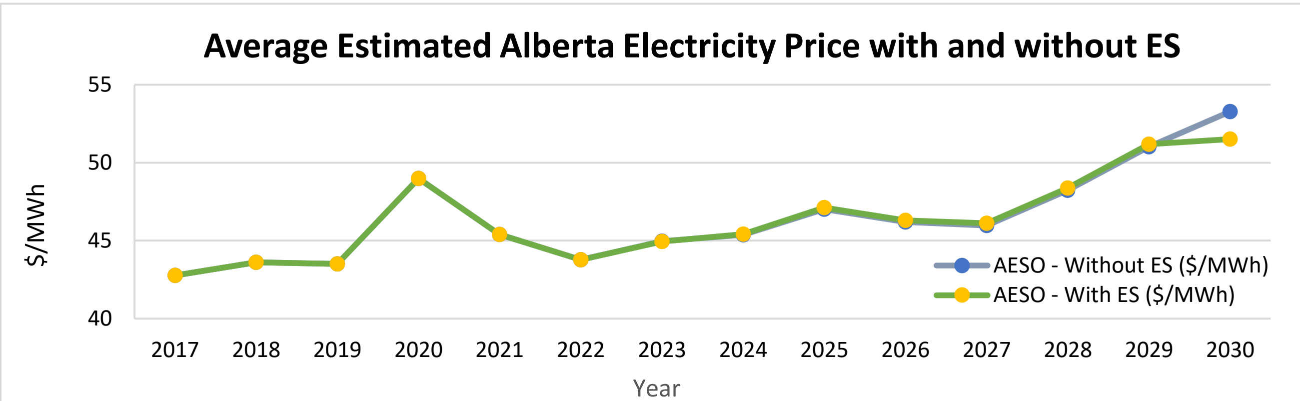


Figure 1-6: Hourly electricity prices over the study period (Benchmark vs. ES Capacity))

Figure 1-7 shows a comparison of the hourly prices in the final year of the study horizon (2030) with and without ES, which provides a good indicator of any potential price effect from ES deployments. It can be seen in the figure that the model predicts that the 2030 Alberta Hourly Electricity Price with ES significantly reduces the volatility and cost per MWh compared to the benchmark. The multi-year variation for fuel consumption and fuel source is depicted in Appendix 1.

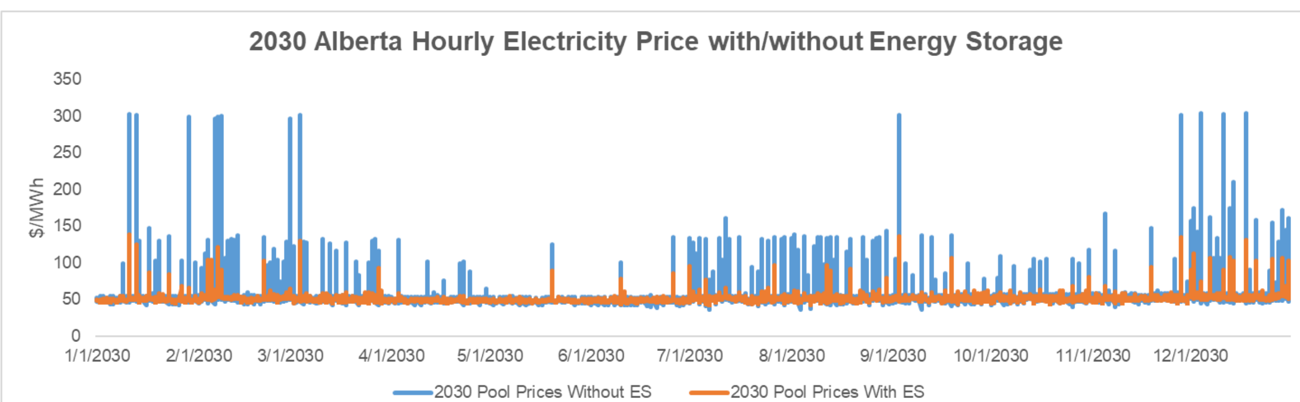


Figure 1-7: Hourly Electricity Price Comparison (Benchmark vs ES Capacity) in 2030

1.5.2.2 Energy Generation Mix

The energy generation mix for Alberta for the base case is shown below in Figure 1-8.

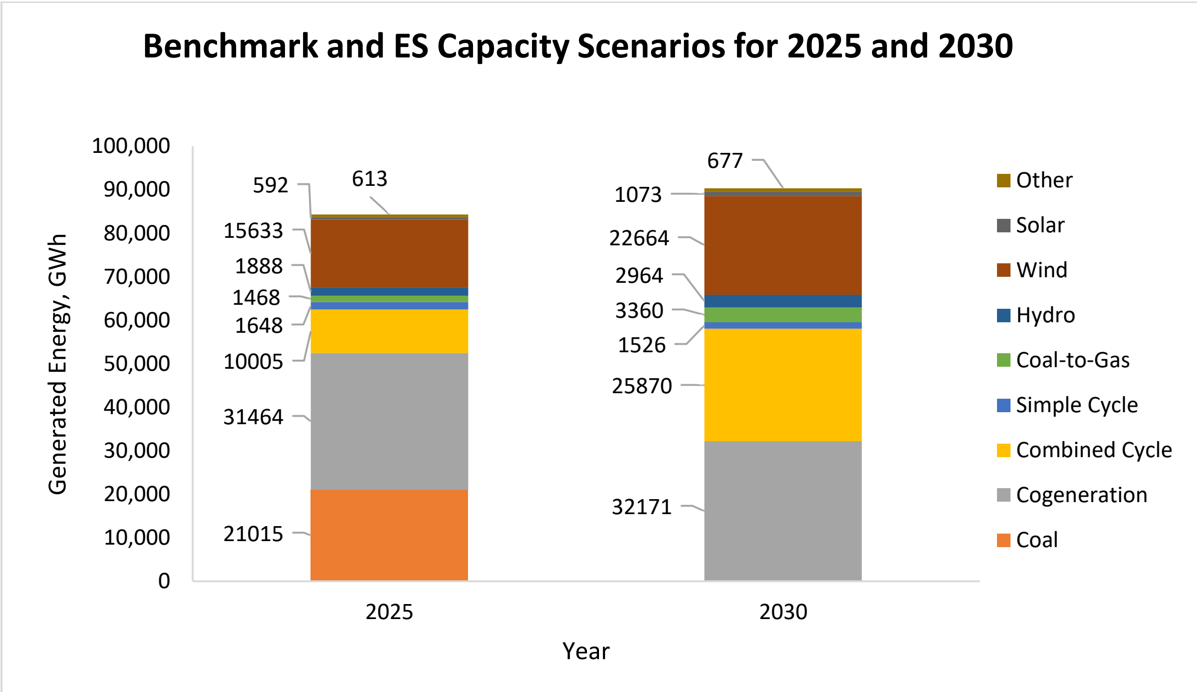


Figure 1-8: Energy generation mix for the Benchmark and ES Capacity Scenario, in years 2025 and 2030.

Note that the years 2025 and 2030 production cost optimization outputs for the benchmark are represented to demonstrate the model used in the study aligned with AESO “reference case” trajectory. The generation mix shown here for the benchmark can be used for comparisons with the generation mixes under the sensitivity analyses performed below.

1.5.2.3 Estimated Benefits and Cost Reductions

The benefits and cost reductions estimated for the deployment of ES over the study period for the benchmark are grouped in 6 categories, as shown in Table 1-7 below. As can be seen, the Peaking Plant Capital Savings creates the highest financial impact ($283MM). For comparison purposes, this is more than an order of magnitude higher than the lowest financial impact category (T&D Cost Savings - $20MM).

Table 1-7: Benefits and cost reductions over the study period, ES Capacity Scenario

Benefit Categories	NPV ($MM, 2017)
Generation Cost Reduction	$36
Regulation & Spinning Reserve Cost Savings	$123
Peaking Plant Capital Savings	$283
Frequency Response Cost Savings	$41
T&D Cost Reduction	$20
Distribution Value	$66
Total Benefit	$568

Cost	$413
Net Benefit	$155

Potential net benefits of $155M were estimated when the recommended storage was deployed as per the optimized schedule due to fuel savings and other operational cost reductions.

Despite the benefits shown above however, ES is shown to have a negligible impact in reducing overall fuel consumption (gas at end of study period): 566,377 k MMBTU (with ES deployed) vs. 570,782 k MMBTU (without ES deployed); less than 1%.

1.5.3 Case 2: Transmission Deferral/Avoidance Scenario

A further high-level case analysis was done to evaluate the potential for using ES to avoid or defer major transmission upgrades. To reach 30% of internal load met by renewables, the AESO expects that an additional 5000MW of wind and 700MW of solar will be in service by 2030. The AESO and Alberta transmission facilities owners have proposed 3 major transmission reinforcement projects (Table 1-8) with a total estimated capital expenditure of $1,275M. Their location is presented in the map below.

Table 1-8: Planned New Transmission Lines

Node From	Node To	Max Flow (MVA)
Chapel Rock	Pincher Creek	977
Tinchebray	Gaetz	700
Provost (Hansman Lake area)	Edgerton	636

More details about the proposed project can be found in AESO's (2015) long-term transmission plan[35].

[35] https://www.aeso.ca/grid/long-term-transmission-plan/

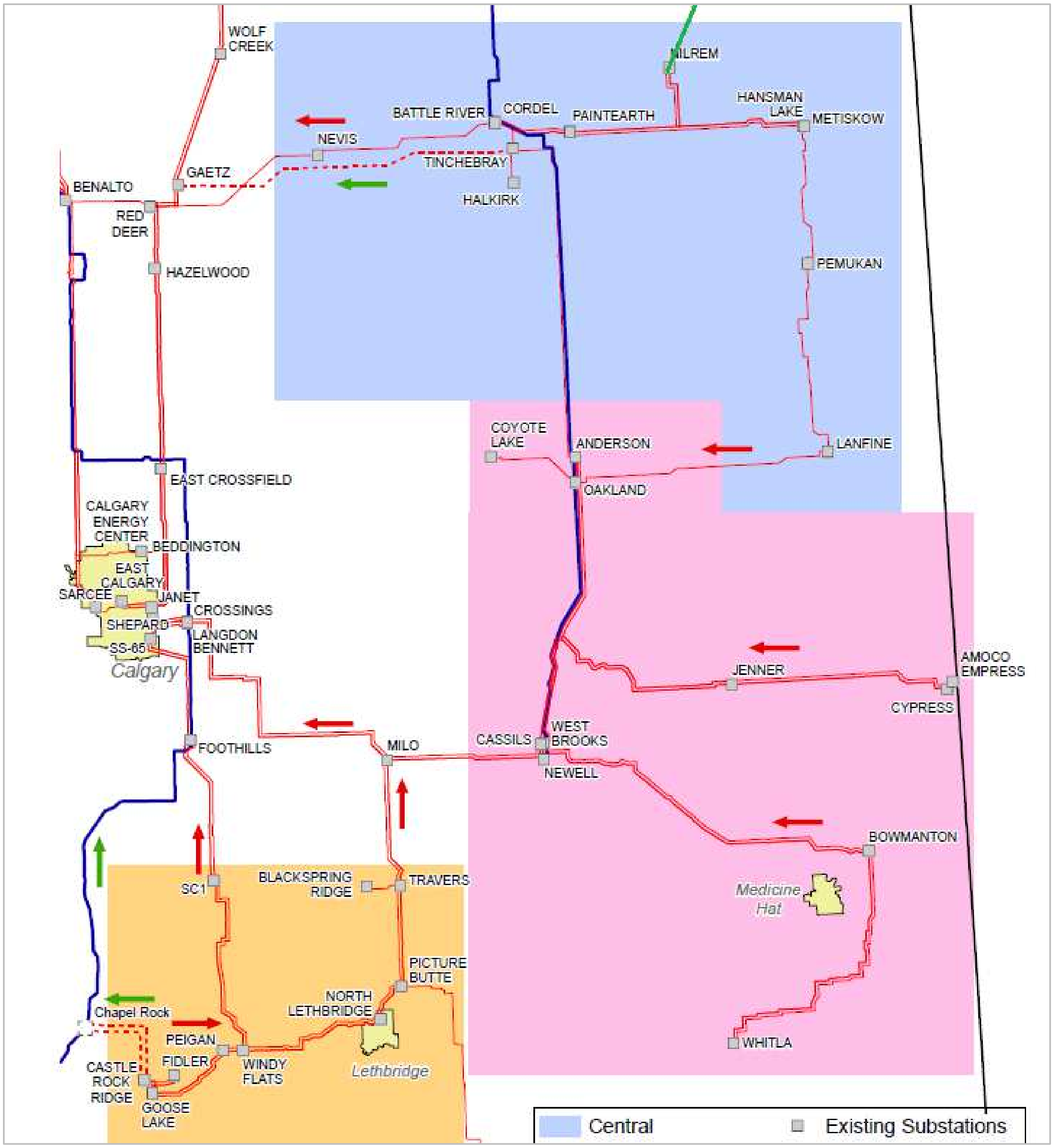


Figure 1-9: Proposed AESO transmission lines in Southern and Central Alberta

1.5.3.1 Storage Facilities Scenario

To align with the Western Regional Electricity Cooperation and Strategic Infrastructure (RESCI) study, a storage scenario to add 1500MW of CAES at three separate locations of 500MW each was evaluated that could be considered as an alternative to transmission system reinforcement. Each CAES storage facility was assumed to have a duration of 10Hr and an efficiency of 77%, and that geology was sufficient in each region to allow for CAES application. The locations (Cordel region, North Lethbridge region, and Goose Lake region) of the three potential storage facilities are shown as blue circles on the map below (Figure 1-10).

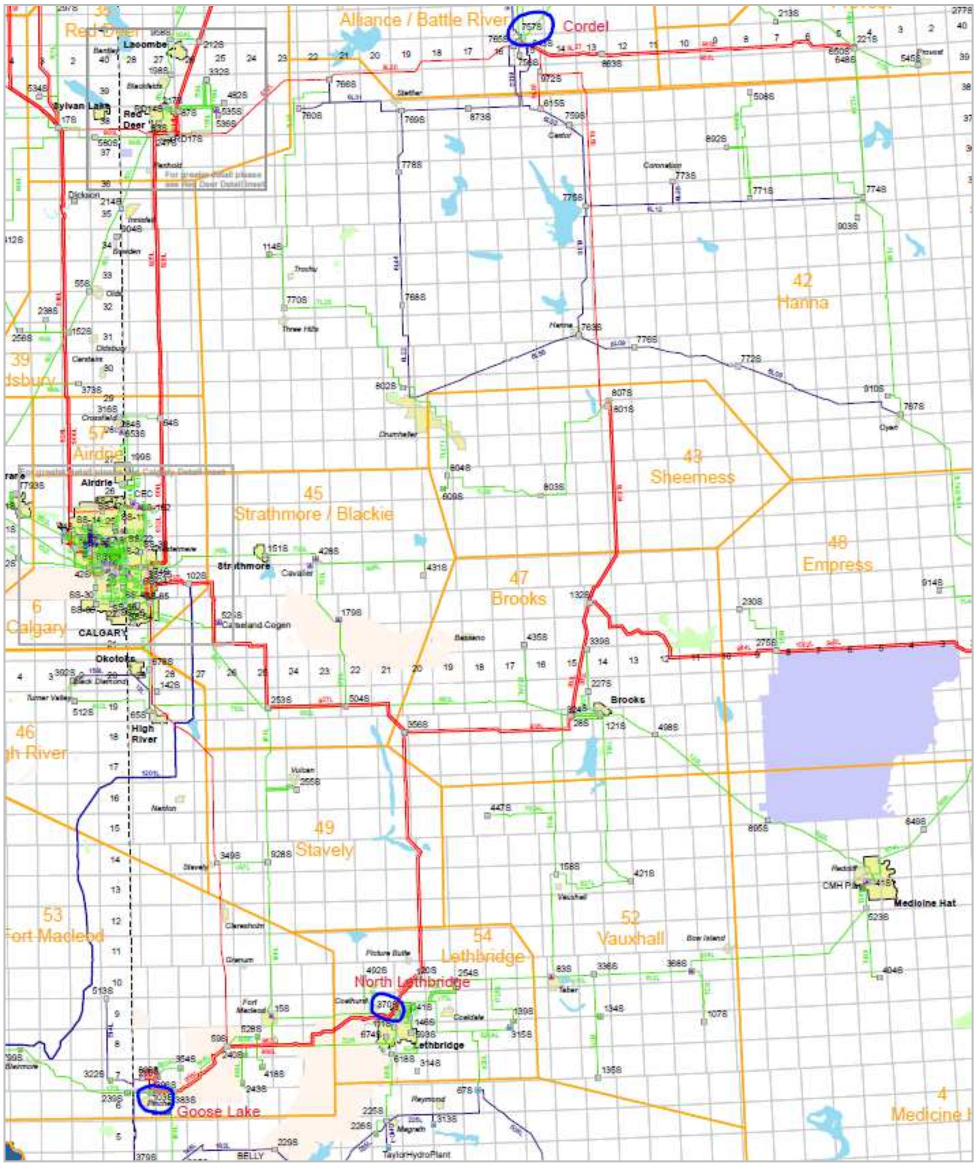


Figure 1-10: AESO alternative ES scenario facilities (Cordel region, North Lethbridge region, and Goose Lake region).

The RECSI study indicated the estimated capital cost of this alternative scenario to be $3 Billion.

1.5.3.2 Comparison of Economics of Transmission vs ES

In order to understand the feasibility of alternative ES solutions to the wire solutions for the increased wind generation in Southern and Central Alberta by 2030, the following analyses were performed.

1.5.3.2.1 Generation Cost and Cost-to-Load

Table 1-9: Transmission vs ES: Generation Cost and Cost to Load (Acelerex Production Cost Model)

Property	Units	New Trans Lines (NTL)	1500MW ES	Delta (NTL-ES)
Total Generation Cost	$000	2,776,996	2,776,266	730
Cost to Load	$000	4,640,149	4,611,578	28,571

1.5.3.2.2 Capital and Maintenance Costs

Table 1-10: Transmission vs Energy Storage: Capital and Maintenance Costs (Acelerex Production Cost Model)

Solution	Capital Cost	Maintenance Costs	System Economic Benefits
Transmission Additions	$1.25B	$3.2M/yr	0
ES Additions 1500MW CAES Transmission Connected	$1.35B to $3B	$17M/yr	EPS36: $28.5M/yr CPS37: >$20M
ES Additions 1500MW Adv. ESS Distribution Connected	$1.35B to $2.5B	$25M/yr	EPS: $28.5M/yr D Value: $45M CPS: > $20M

1.5.3.3 Observations (Transmission Deferral/Avoidance Scenario)

- A high-level assessment of economic storage vs a transmission solution suggests that there may be a set of assumptions and valuations that the storage solution can be economic compared to the transmission solution.
- A detailed Net Present Value (NPV) analysis of benefits and costs ought to be performed on the economic storage solution. Additional storage for reliability purposes of integrating wind energy ought to be economically tested against the transmission solution.
- If the cost of ES technology continues to decline, there is the potential to use ES to replace wire solutions in transmission infrastructure. However, a detailed dispatch analysis needs to be performed.

1.5.4 Case 3 and 4: Sensitivity Study - Fuel Prices

As described above, the first sensitivity study was completed by varying the fuel pricing in the model. The results of the high fuel price variant (+40%) and the low fuel price variant (-40%) are presented below for comparison purposes.

1.5.4.1 Potential ES Capacity with Varied Fuel Pricings

The size and timeline of ES deployments over the study horizon for the high and low fuel prices variants are shown below in Table 1-11 and Table 1-12, respectively.

Table 1-11: Potential ES capacity (high fuel prices variant)

High Fuel Prices Case									
Deployment Category	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Capacity (MW)**
Long Duration	--	--	--	--	--	--	--	785	785
Medium-Long Duration	--	--	--	--	--	--	82	--	82

[36] EPS: Earnings per share.

[37] CPS (cash EPS): Cash earnings per share.

Medium-Short Duration	--	--	--	105	120	--	--	--	225
Short Duration	75	--	--	--	--	--	--	--	75
High Fuel Price Total	**75**	**--**	**--**	**105**	**120**	**--**	**82**	**785**	**1167**

Table 1-12: Potential ES (low fuel prices variant)

Low Fuel Prices Case									
Deployment Category	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Capacity (MW)**
Long Duration	--	--	--	--	--	--	--	777	777
Medium-Long Duration	--	--	--	--	--	--	74	--	74
Medium-Short Duration	--	--	--	--	--	--	210	15	225
Short Duration	--	--	--	75	--	--	--	--	75
Low Fuel Price Total	**--**	**--**	**--**	**75**	**--**	**--**	**283**	**793**	**1151**

A comparison of the capacity totals shown in the figures above indicates relatively minor changes from the benchmark. For the high fuel price variant, the total potential ES capacity increased slightly from the benchmark scenario (from 1152MW to 1167MW) because some ES became more cost-effective than conventional generation at high fuel prices. For the low fuel price variant, the total potential ES capacity was relatively unchanged in comparison with the benchmark scenario (1151MW for the low fuel variant compared to 1152MW for the benchmark). This indicates that when fuel prices are low, ES deployments are more significantly driven by other factors.

In addition, the category of storage technologies does not vary significantly with changes to fuel prices. Higher fuel prices decrease the amount of long duration ES technology capacity by only about 0.5% of installed ES capacity.

1.5.4.2 Electricity Prices Based On Fuel Price Variability

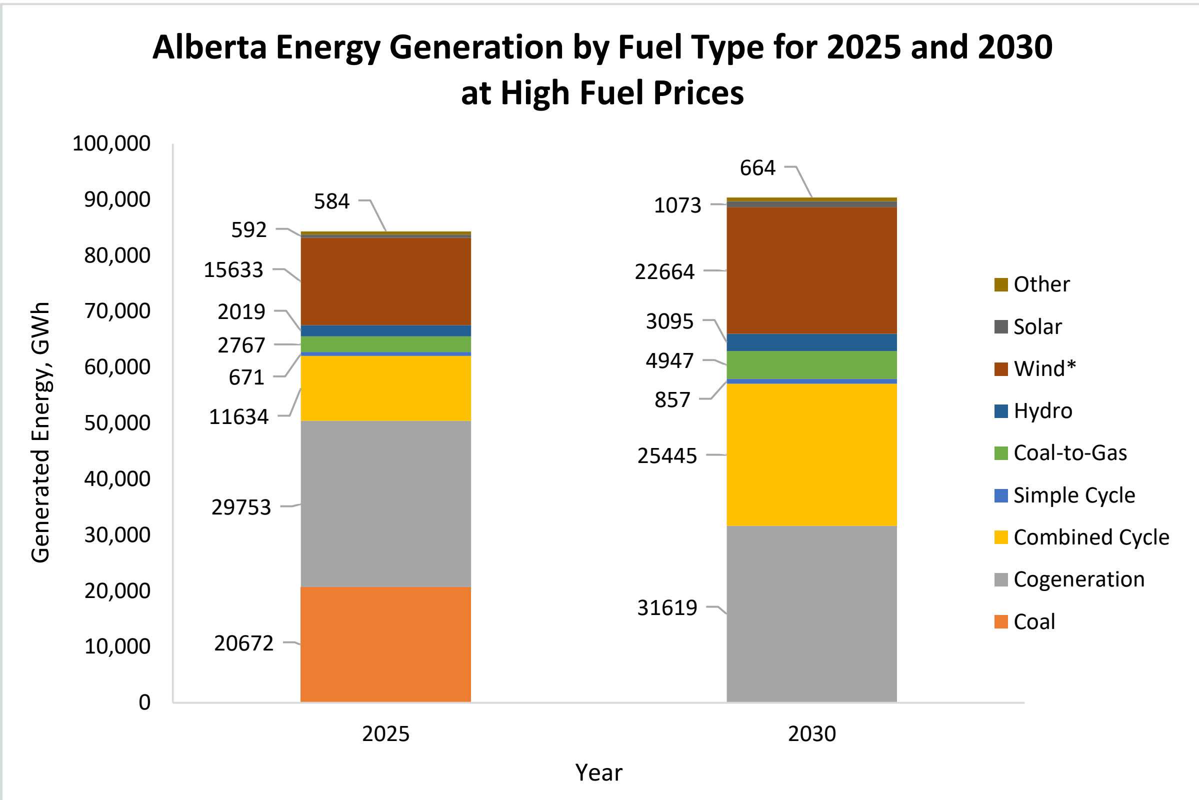
The average annual electricity prices for the ES Capacity Scenario and the high and low fuel price cases are presented for comparison purposes in Table 1-13. As Alberta's generation fleet contains predominantly thermal generators today and in 2030, the fuel prices have a significant impact on electricity prices. At the high fuel price case (+40%), the electricity price increases by 31% (and decreases by the same amount for the low fuel price case).

Table 1-13: Average Annual Electricity Price, Influence of Fuel Prices (AESO, $/MWh)

Average annual electricity price AESO ($/MWh),	2025	2030
Case: High fuel prices	61.7	67.9
Case 1: ES Capacity	47.1	51.5
Case 4: Low fuel prices	32.6	35.7

1.5.4.3 Energy Generation Mix

Values for the generated energy by fuel type for the high and low fuel prices cases are shown in Figure 1-11. A comparison of the bar charts shows that there is significantly more Coal-To-Gas (260% increase, or 12856 GWh more vs 4947 GWh) of generated energy in the low fuel prices case compared to the high fuel prices case. The reason for this is that when fuel prices are low, gas-fuel thermal generation units are dispatched more to charge ES. Since ES does not produce energy, it is treated as a price taker in the grid.



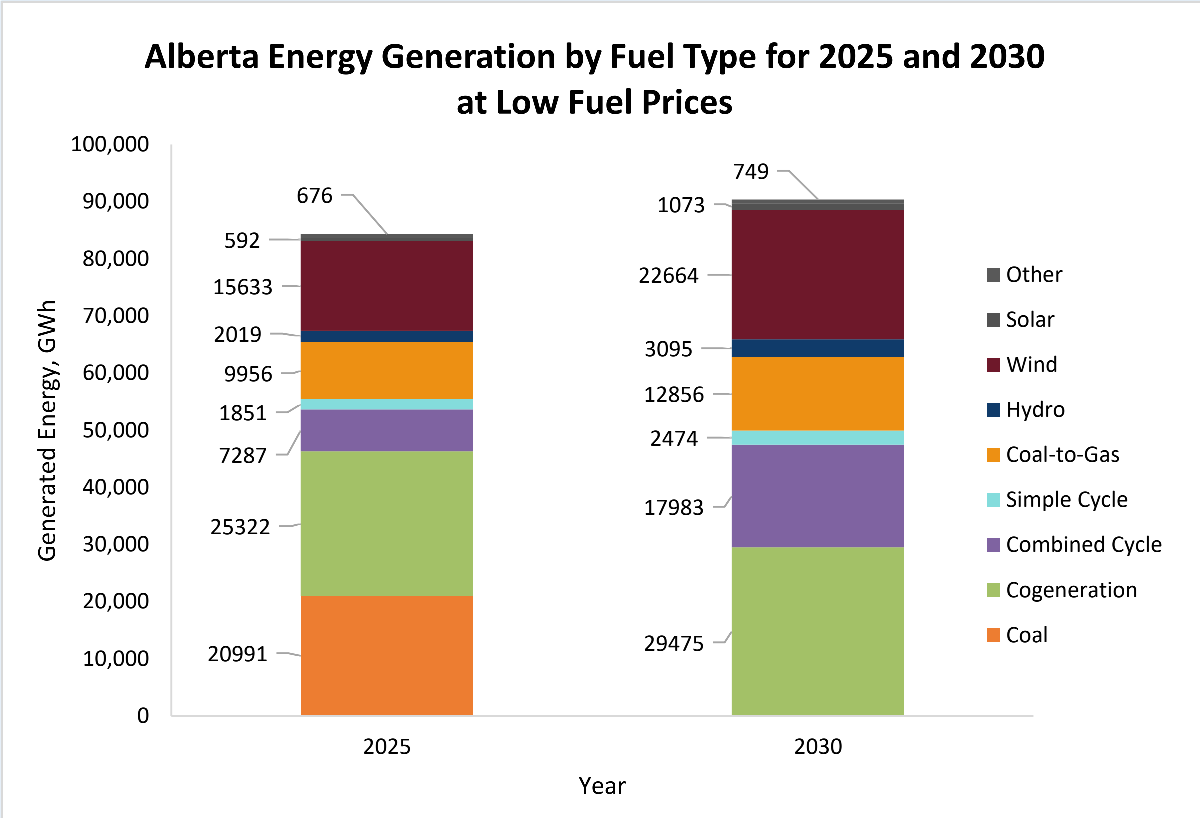


Figure 1-11: Energy from various generation assets by fuel type (influence of fuel prices, years 2025 and 2030).

1.5.4.4 Estimated Benefits and Cost Reductions

The results of this sensitivity analysis show that with higher fuel prices, a further decrease in overall fuel consumption was seen with ES deployments; 5% decrease in gas (in K MMBTU, gas representing 98.4% of all fuels consumed at the end of the study period).

1.5.5 Case 5 and 6: Sensitivity Study - Influence of ES Technology Costs

As discussed previously, this sensitivity study was performed to quantify the impacts of varying ES technology capital costs using the range for prices from -40% to 40%.

1.5.5.1 Potential ES Capacity with Varied ES Technology Costs

The size and timeline of ES deployments over the study horizon for the high and low technology capital cost cases are shown below in Table 1-14 and Table 1-15, respectively.

Table 1-14: Potential ES capacity (high ES technology cost case)

Case 5: High Technology Cost									
Deployment Category	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Capacity (MW)**
Long Duration	--	--	--	--	--	--	--		
Medium-Long Duration	--	--	--	--	--	--	--	16	16

Medium-Short Duration	--	--	--	--	--	--	14	211	225
Short Duration	--	--	3	72	--	--	--	--	75
High Tech Cost Total	**--**	**--**	**3**	**72**	**--**	**--**	**14**	**227**	**316**

Table 1-15: Potential ES capacity (low ES technology cost case)

Case 6: Low Technology Cost									
Deployment Category	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Capacity (MW)**
Long Duration	--	--	--	417	128	290	--	--	835
Medium-Long Duration	--	--	--	--	--	--	686	39	725
Medium-Short Duration	--	225	--	--	--	--	--	--	225
Short Duration	75	--	--	--	--	--	--	--	75
Low Tech Cost Total	**75**	**225**	**--**	**417**	**128**	**290**	**686**	**39**	**1860**

Unlike the sensitivity analysis for fuel prices, there was a large impact of technology cost observed on the potential market for ES. An 80% change (-40% in the low cost case scenario to + 40% in the high cost case scenario) in technology costs resulted in a change of potential installed capacity from 316MW (in the high technology costs scenario) to 1860MW (in the low technology costs scenario). ES deployment is also seen much earlier in the low technology cost case compared to the ES Capacity Scenario.

1.5.5.2 Electricity Prices Based on ES Technology Price Variability

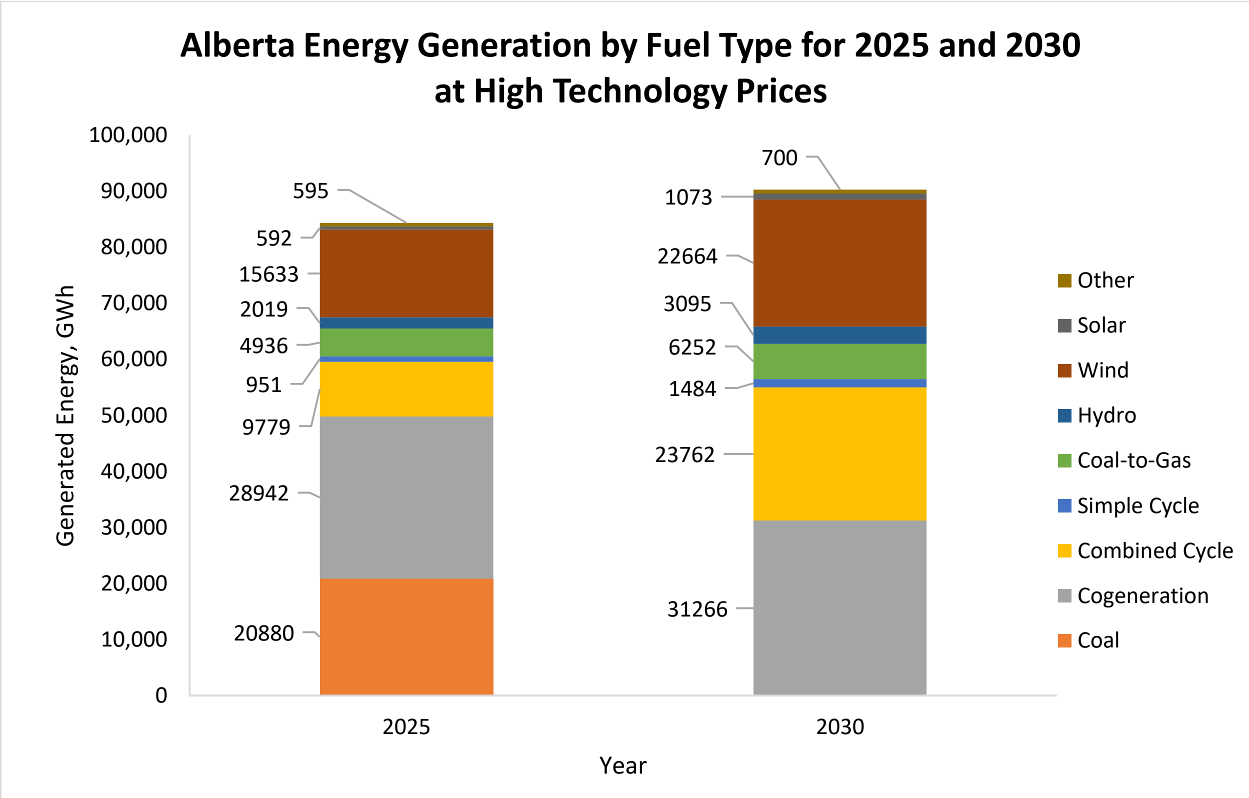
As can be seen in Table 1-16 below, the high and the low technology capital cost cases provided similar results regarding evolution of electricity prices. The power price variation ranged between $47 and $52.6/MWh over the study period (2017-2030). From this simulation, technology prices did not have a noticeable impact on electricity prices.

Table 1-16: Average Annual Electricity Price, Influence of ES technology capital costs (AESO, $/MWh)

Average Annual Electricity Price AESO ($/MWh)	2025	2030
High ES technology capital cost case	47.0	52.6
Low ES technology capital cost case	47.4	52.0

1.5.5.3 Generated Energy Mix

Values for the generated energy by fuel type for the high and low fuel prices cases are shown in Figure 1-12.



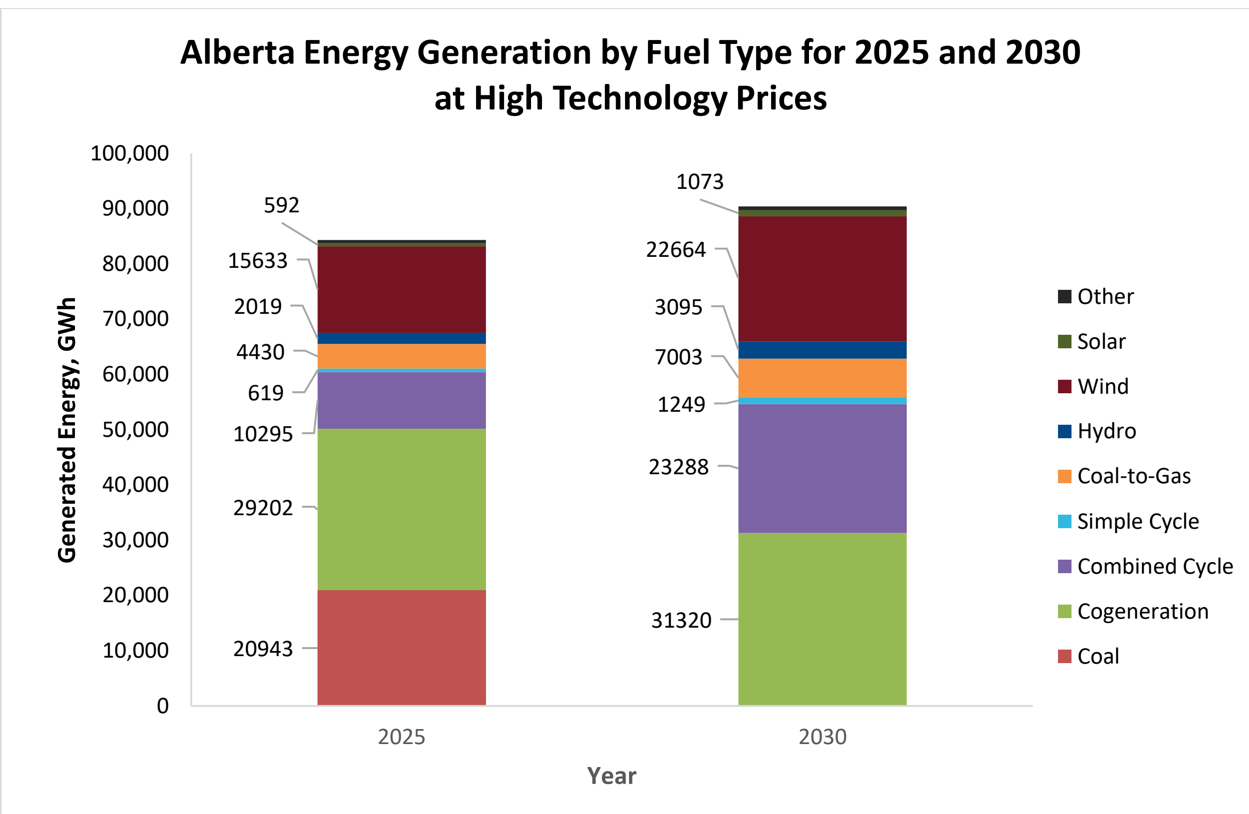


Figure 1-12: Energy from various generation assets by fuel type (influence of technology costs, years 2025 and 2030)

1.6 Overall Conclusions Related to the Potential Market for ES in Alberta

Pillar 1 takes a technology-agnostic approach to evaluate the overall market potential for ES in the province over the 2017 - 2030 timespan. At each node on the transmission grid, broad categories of ES technology deployments were simulated at additional capacity. The overall impact of this additional capacity on the electric grid was then assessed by analyzing changes in the pool prices as well as other potential benefits such as generation cost savings, peaking plants capital savings, and other economic drivers.

Utilizing the methodology, inputs, and assumptions described above, simulations were performed and outputs were generated. Based on the simulation results, the most important conclusion that can be drawn is that there is a market opportunity for ES systems in the Alberta electric system. Specific results of interest from the analysis for the potential new ES capacity in Alberta include the following[38]:

- In consideration of the expected load growth in Alberta and the generation retirement/development plan, approximately 1152MW of ES could be deployed from 2017 – 2030, with modest financial benefits seen with a minimal amount of ES implementation due to the cost of the technology. By 2029/2030 however, as the cost of ES technology is expected to significantly reduce, the benefits of ES start to outweigh the costs. DTS/STS were considered as part of the FOM of ES in the model. Their impact to ES is similar to what they would be for conventional generation or load. Assuming ES is utilized 100% of the time, DTS and STS are both applied 50% of the time. This does not make ES less competitive than conventional generation technologies, but the cost of ES technology will have a bigger impact.
- The first cost-effective ES deployment was estimated to be online by 2024 (ES Capacity Scenario), and a year earlier (2023) when sensitivities are factored in (high fuel price case and low technology capital cost case). These are the respective years when the annual revenues from the services provided by the ES systems become greater than their operational costs.
- Under all the scenarios/sensitivities, new ES capacity is deployable up to the last year of the study period (2030).
- All scenarios and sensitivity cases identified opportunities for deployment of the four categories of ES technologies regarding storage time length (Long (L), Medium-Long (ML), Medium-Short (MS) and Short (S)) except the high technology capital cost case where no Long duration ES technologies potential were identified in AIES.

If the above potential ES capacity was deployed, it is estimated that there would be several significant benefits to the grid and to ratepayers that include the following:

- A potential of $155M net benefit when 1152MW of ES was deployed.
- Electricity prices exhibit less volatility when ES systems are deployed to perform a variety of services in the bulk electric system, even though a large amount of renewable generation is implemented. The reduced electricity price volatility is due to reduced cost of load in the ES deployment case. This includes energy arbitrage as well as ancillary cost and capacity cost reduction.

[38] As stated in the Preface (pp. ii and iii), the policy changes that have taken effect since the analysis presented in this report was performed will likely have an impact on the results presented here. Specifically, the policy changes could lead to a decrease of up to 20% in the number of ES projects (all of which are long-duration applications).

- The capital costs of ES technology have a significant impact on ES deployment. A 40% reduction in ES technology costs will yield a 60% increase in ES deployment.

2 Technology Assessment and Valuation Pillar

Pillar 2 is a micro-level analysis that simulates the profitability, technical performance, and dispatch of a single, grid-connected ES unit. The Pillar 2 analysis matches technology and application requirements, proposes valuation and performance frameworks, and evaluates individual ES profitability and dispatch on the electric grid. Details on Pillar 2 objectives, background, methodology, and results are provided in the sections below.

2.1 Introduction to Pillar 2

Despite the expectations of many regarding the potential benefits from grid-scale storage technologies[39], the complexity of markets, technologies, and integration at a project level often make these benefits difficult to quantify appropriately. There are, however, several evaluation frameworks available that can aid in the decision to adopt energy storage technology and assist in the planning, installation, and demonstration of up to a full commercial operation level. Choosing the appropriate storage technology can be difficult as there are many factors to consider, such as the variety of technology choices available, the diverse application services along the electricity value chain, restrictions or adoption of specific business models at the utility and end user level, and complicated ownership or revenue structures.

Pillar 2 focuses on understanding how specific energy storage (ES) technologies can meet the operational and cost requirements for the nodes outlined in Pillar 1 by simulating specific examples of ES installations at a project level. The goal is to align the larger grid-scale market opportunity already outlined in Pillar 1 with an equipment operator and/or asset owner's point of view to determine the viability of individual projects. This is achieved by:

- A valuation analysis of investment in potential advanced ES technologies compared to conventional resources such as gas combustion turbines for distributed generation use cases
- Reviewing the multi-year performance of the potential ES projects given future market scenarios and analyzing typical financial or ownership structures to determine where benefits might accrue on potential ES projects given the constraints above

It should be noted that while the analysis in Pillar 1 is technology-agnostic and takes a system level approach to ES on the AIES, the analysis in Pillar 2 is both project and technology-specific in order to meet the goals above. By simulating individual ES technologies operating at a specific location on the AIES, it becomes possible to bring real world cost, performance, and market information into the analysis, and determine which technologies and grid benefits outlined in Pillar 1 are viable under current and proposed regulations and market structures. While not fully comprehensive, it provides a starting point for a comparative discussion of potential policy or market options to pursue in order to achieve the "lowest cost" system outlined in Pillar 1.

2.1.1 Relation to Pillar 1

The valuation analysis in this section simulates a single ES unit at a time, thus all inputs are assumed to be static. This is inherent in the simulation tool's design. The simulation does not take into account the effect of ES on system-level price and load data because of the insignificant impact of a single ES unit operating on the AIES. The dynamic effect of aggregated ES units on pool price and load data could be significant and is accounted for at the system level in Pillar 1's production cost model. Pillar 2's storage valuation therefore uses actual historical

[39] (Zhenguo, et al. 2013, Barnhart and Benson 2013)

wholesale market electricity / pool prices, ancillary service price, and load data from AESO. There are two reasons for the latter. First, in the grid scale energy storage analysis in Pillar 1, ES capacity is added at the system level at different time intervals over the fourteen year study period with various pool prices. Second, changing ES capacity and pool price also influence ancillary service price and load data. This requires similar price and load outputs from system level calculations (Pillar 1) that are too granular for the system level modelling. As a reasonable approximation, the Pillar 2 analysis involves calculating increases in pool prices as well as ancillary service price and load data using macroeconomic indicators like inflation and fuel escalation rate inputs.

2.2 Background: Analysis, Market, and Technical Considerations

2.2.1 Market Considerations

Reductions in total cost, including capital and operating costs, of energy storage systems over the past decade have attracted interest from system operators, generators and technology vendors across customer-sited, transmission, and distribution-connected electric grids worldwide. Electricity systems face many challenges including how to analyze each proposed project on the grid, how to access the markets, and where the benefits might be accrued.

While each market has unique attributes, some markets and services common to Canadian and American Independent System Operators (ISO's) and Regional Transmission Organizations (RTO's) have been identified in other analyses[40]. These standard definitions could be customized to match Alberta's markets and services for today and in the future; however, each of these require detailed information on market dynamics, pricing, and load data. Fortunately, given Alberta's deregulated market, much of this information is available from the AESO and published literature, including detailed descriptions of the overall market and the operation of submarkets. Table 2-1 provides a summary of the current Alberta markets and services.

Looking at other electricity markets, in the United States, US FERC Order 841 was an important step allowing ES to access value in these wholesale energy markets, ancillary services and capacity markets[41]. This has impacted several ISO/RTO's, including PJM, CAISO, ERCOT, NYISO, ISONE, and MISO. PJM has rectified its market rules to allow fast ramping projects to participate in the Reg D service. PJM is also working on proposals to allow ES systems to participate in energy and capacity markets as dispatchable assets. Finally PJM is proposing a 5-minute real-time market settlement time interval, which allows ES to maximize revenue as well as allowing smaller MW-rated ES systems to participate. PJM's capacity market requirements remain largely unchanged.

More recently, from Q1 2013 to Q4 2018, US ES growth came from large, long duration installations where capacity markets of at least 4 hours' duration were the key application[42]. In Arizona, ES is being used for long-term transmission deferral[43] and ES as a transmission asset is being considered by CAISO and MISO[44]. This is an application that could be relevant to Alberta. Alberta and BC are part of the Western Interconnection (WECC). CAISO has initiated the Western Energy Imbalance Market (EIM) to deal with increasing variability due to

[40] (Akhil, Huff and Currier 2015, Electric Power Research Institute 2014)

[41] (Ruiz, et al. 2018)

[42] (Simon, Finn-Foley and Gupta 2019)

[43] (Scottmadden Management Consultants 2018)

[44] (Simon, Finn-Foley and Gupta 2019)

thermal retirements and wind plus solar additions across WECC. BC Hydro's Powerex began participating in CAISO's EIM market as of April 2018[45]. This is a new market Alberta could participate in, not only with ES, but also with planned natural gas as well as wind capacity additions and coal capacity retirements. There is a significant upside for ES in ERCOT's first significant overhaul of its ancillary services market[46] which Alberta could monitor and learn from.

Table 2-1: Overview of AESO Markets and Services

Market / Service	Submarket	Service	Purpose
Wholesale Electricity Markets	Energy Market		Facilitate fair, efficient and open transactions for selling, purchasing and trading energy in the Alberta Interconnect Electric System (AIES) to maintain bulk electric system reliability while ensuring competitive electricity pricing.[47] [48]
	Capacity Market (*No longer planned for AB)		The Alberta capacity market would be a mechanism to achieve resource adequacy and meet the government-defined resource adequacy standard at least cost by enabling broad competition among capacity resources. The first capacity market auction was to commence in 2019 with first delivery of capacity to occur in 2021.[49]
Ancillary Services Market	Operating Reserve	Regulating	Due to the size and complexity of the AIES, the balance between dispatched generation (supply) and consumption (demand) is not instantaneous – often there is a lag while generation is catching up to supply or while generation is decreasing in response to lower demand. Regulating reserves instantaneously provide the power difference between supply and demand required during that lag period.[50]
		Contingency – Spinning / Supplemental	Spinning and supplemental reserves (collectively referred to as contingency reserves) are used to maintain the balance of supply and demand when an unexpected system event occurs. These reserves provide capacity so the AESO can respond in short notice to correct any imbalance. These reserves can come from the supply side (generators) or from the demand side (load curtailment by reducing demand from large electrical consumers immediately). Spinning reserves are the fastest acting contingency reserve. Generators or loads providing spinning reserves are synchronized to the grid (the turbine is "spinning" but not generating power). This unique feature allows the

[45] California ISO, 2018

[46] (Simon, Finn-Foley and Gupta 2019)

[47] https://www.aeso.ca/market/market-and-system-reporting/

[48] https://www.aeso.ca/market/understanding-the-market/

[49] https://www.aeso.ca/market/capacity-market-transition/

[50] https://www.aeso.ca/market/ancillary-services/operating-reserve/

		reserve to be provided very quickly. In addition to responding quickly, spinning reserves also provide frequency support to the system. Supplemental reserves on the other hand are not required to be synchronized to the grid.[50]
	Transmission Must Run (TMR)	In the event of constraints on the transmission system, AESO follows prescribed rules and procedures and uses tools to manage the system. Transmission Must-Run (TMR) is a service that requires generation to be online and operating at a specified output level in particular areas of the province to compensate for insufficient transmission infrastructure relative to the local demand. The use of TMR as a non-wires solution is limited by regulation and is managed by transmission development.[51]
	Dispatch Down Service (DDS)	In order to compensate for the effect that TMR generators may have on pool price, AESO uses a service called Dispatch Down Service (DDS) whereby eligible generators receive a payment for reducing generation levels or dispatching off in proportion to the amount of TMR online when the system marginal price is less than a TMR "reference price."[51]
	Black Start Services (BSS)	The AESO contracts for Black Start Service (BSS) with generators who are able to start their generation facility with no outside source of power. In the unlikely event of a system-wide blackout, Black Start providers are called upon to re-energize the transmission system and provide start-up power to generators that cannot self-start.[52]
	Load Shed Services for imports (LSSi)	Load Shed Services for imports (LSSi) are control systems that allow the AESO to instantly reduce demand on the system when an unexpected system event occurs. The AESO contracts with large consumers of electricity to provide LSSi. When required, the AESO can automatically trip off or curtail these consumers in order to balance supply and demand.[53]

It is of vital importance to understand how to value an ES project against a traditional wires alternative, and/or how it should be impacted by various transmission or distribution charges. This can be separated into two common issues:

- Transmission Investment Deferral - Transmission Investment Deferral is not currently part of the AESO's Markets or Services. However, AESO has investigated using ES for Transmission Investment Deferral in specific cases. Additionally, both industry and government have an interest in understanding how ES could

[51] https://www.aeso.ca/market/ancillary-services/transmission-must-run-service/

[52] https://www.aeso.ca/market/ancillary-services/black-start-services/

[53] https://www.aeso.ca/market/ancillary-services/load-shed-service-for-imports/

defer transmission investments to mitigate transmission constraints, either in the adoption of renewable generation or addressing local congestion issues.

- Transmission and Distribution Charges – Advocates of ES often suggest that ES should either be exempt from transmission or distribution charges, or at least not pay them twice in order to level the playing field between ES and conventional assets. This is usually attributed to the system wide benefits that might be provided by ES, which are difficult to quantify at a project level. This is the reason for the analysis in Pillar 1, and largely, those conclusions support this assertion. Currently, the 2018 AESO tariff includes Supply Transmission Service (STS) incremental pricing for generators and Demand Transmission Service (DTS) pricing for load[54]. Note that neither DTS nor STS costs were explicitly considered in Pillar 2's valuation model. For an explanation, refer to section 2.4.1, "Model Inputs and Assumptions"

2.2.2 Analytical Tools and Methodologies

The viability of any energy storage project depends upon location, a market structure that enables the valuation of benefits, and the cost and performance of the energy storage technology[55]. At a project level, several tools have been developed to analyze the value of distributed storage technologies for various grid applications[56]. In many of these tools, the underlying assumption is that the operation of any single energy storage system will not significantly influence market conditions, and therefore the existing market prices are used as a fixed input[57]. This is one of the fundamental differences between this project level valuation tool, which focuses on economic dispatch and understanding stacking benefits and costs, and the electricity production cost models, as used in Pillar 1. The project level valuation tool also allows for a discrete analysis at a project level which can clearly identify monetization and cost-benefit ratios of relevant grid services. It therefore allows an increased understanding of the value that an individual ES system creates for its owner, and whether it is economically viable to build such a system.

Presented below are results over the technology lifetime and normalized results to compare different power and duration ratings across technologies.

The wide variety of technology choices and diverse applications along the electricity value chain makes the choice of appropriate ES technology difficult[58]. From a utility perspective, Southern California Edison (SCE) noted the lack of storage project parameters in the context of existing infrastructure. This lack of clarity from utilities around value propositions and technical needs makes it difficult for the manufacturer to improve ES cost effectiveness and performance. Therefore, an application-focused valuation methodology was introduced by SCE[59]. In addition, the NREL valuation analysis tool evaluates the operational benefit of commercial storage applications, including load-leveling, spinning reserves, and regulation reserves[60]. Finally, the Energy Storage

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[54] Rules, Standards and Tariff AESO 2018

[55] (Kirby, Ma and O'Malley May 2013)

[56] (Zhenguo, et al. 2013)

[57] (Pearre and Swan 2014)

[58] (Denholm, Jorgenson, et al. May 2013, Kaun June 2013)

[59] (Rittershausen and McDonagh 2013)

[60] (Denholm, Jorgenson, et al. May 2013)

Valuation Tool (ESVT) developed by EPRI[61], proposes a methodology for separating and clarifying analytical stages for storage valuation. ESVT calculates the value of ES by considering the full scope of the electricity system including system/market, transmission, distribution, and customer services; and in ES-Select™, designed and developed by DNV-KEMA, the user must choose where ES is connected to an electric grid[62].

Lazard provides a comprehensive technology assessment framework based on the levelized cost of storage LCOS[63]. One should note that LCOS only analyzes observed costs and revenue streams from the project and is generally an empirical indication for equipment costs and associated revenues. LCOS reported by Lazard is based on aggregating cost and operational data from original equipment manufacturers' technology developers and is only applicable to a select subset of identified use cases by Lazard [64].

Additional details of how these tools were utilized and adapted in this study are described in Appendices VII and VIII.

2.2.3 Technical Considerations

ES technologies are being developed and commercialized by numerous companies and organizations around the world, and range in maturity from very early stage research and development (R&D) to fully commercial repeatedly deployed systems[65]. The maturity of an ES technology can be assessed by using Technology Readiness Level (TRL) and Manufacturing Readiness Level (MRL).[66]

In general, TRL1 refers to an innovation activity at the very basic R&D stage (proof of concept), while TRL9 represents the technology at a commercial stage and market ready. TRL and the risk associated with the maturity of ES systems have been used by the U.S. Department of Energy (USDOE) for providing support for scientific, R&D, and commercialization activities related to grid-scale ES systems. The highest TRL9 is assigned to technologies such as pumped hydro systems which are widely deployed and have a long history of operation, whereas newer technologies, such as solid state lithium batteries, would currently be below TRL6. This study, consistent with other ES studies, evaluates technologies at TRL 8 and above - essentially, commercial at-scale technologies, that are readily available for purchase from a vendor by the owner/operator. These commercial systems usually have more data with respect to ES unit cost, performance and lifetime, including additional information on the full project costs required to build and operate a project including Balance of System (BoS) equipment and installation, and operational fixed and variable costs. The initial capital costs usually include manufacturing and material costs, but may not include commissioning, and end of life costs such as decommissioning, disposal or recycling / repurposing. These end of life costs are not included in analysis in Pillar 2 due to the varied approaches being taken by project proponents with respect to dealing with these eventual costs. They are however addressed in Pillar 3 as part of the full life-cycle assessment of technologies.

[61] (Kaun June 2013)

[62] (DNV KEMA Inc. December 31, 2012)

[63] (Lazard 2016, Lazard 2017)

[64] (Lazard 2016, Lazard 2017)

[65] (Viswanathan, et al. September 2013)

[66] (Engel, et al. October 2012).

MRL is similarly assigned to each storage technology by many studies. The International Energy Agency's (IEA) 2014 Technology Roadmap[67] provided a development spectrum for maturity of ES technologies which closely resembles the TRL and MRL levels defined by Engel et al[68]. In a recent report, USDOE[69] evaluated the risk and technology readiness of ES technologies. Several valuation frameworks were recently proposed that integrate the technology outlook, storage performance matrix, and storage valuation models into a business opportunity assessment[70].

2.3 Methodology

As described above, Pillar 2 involves performing detailed project level techno-economic analysis (TEA) of individual projects in order to:

1) Assess appropriate ES Technologies
    a) Evaluate the impact of specific ES technologies' performance, cost, and operational requirements on the viability of individual projects
    b) Use cost, performance and lifetime data specific to each combustion turbine (CT) and ES technology
2) Assess Benefits
    a) Align ES benefits between AESO markets and services to Pillar 2's valuation of storage for grid services
    b) Use AESO price and load data for those markets and services, and when unavailable, internal estimates are provided
    c) Incorporate current and future AESO market mechanisms including an estimate of Alberta's 2021 capacity market (no longer being planned) (energy-only market and capacity markets are modelled separately), and incorporate potential markets or specific applications including an estimate of transmission investment deferral based on Alberta stakeholder input
    d) Analyze dispatch of an ES technology operating on the AIES
3) Understand the Impact of Financial and Regulatory Structures
    a) Look at reasonable ownership structures, and assess the value which is attributed to each party in the proposed project
    b) Account for macroeconomic factors like fuel escalation, and understand project viability and risk
    c) Incorporate assumptions on financial ratios such as debt to equity ratios, return on equity, and tax rates.

Following a review of the available tools as outlined above, for this study, the Electric Power Research Institute's Energy Storage Valuation Tool (ESVT) 4.0 was used for techno-economic analytics of use cases (Electric Power Research Institute 2014). ESVT is a time-series dispatch simulation tool to analyze the cost-effectiveness of energy storage based on the Analytica™ Power Player with Optimizer software platform by Lumina Decision Systems. In this analysis, the value of energy storage is calculated for a specific use case by taking into account the full electricity system, including system-specific load and price data, financial and cost information, market structure (e.g. regulated or de-regulated), transmission and distribution capacity, and service applications. ESVT is a financial simulation model that allows the user to evaluate the cost-effectiveness of technically feasible grid-connected energy storage system use cases and multiple business cases. The model supports energy storage

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[67] (International Energy Agency 2014)

[68] (Engel, et al. October 2012)

[69] (U.S. Department of Energy December 2013)

[70] (Malek and Nathwani 2016)

grid services covering the full scope of the electric system, from generation, transmission and distribution or "front of meter" down to end user consumption or "behind the meter." ESVT contains preloaded seed data based on actual historical data provided by EPRI partner ISO/RTO's for grid service requirements and values, as well as financial, and economic assumptions. Corresponding actual stakeholder data was then collected to build the Canadian jurisdiction-based database, and that jurisdiction-specific data is used to run TEA simulations.

ESVT simulates energy storage operation for achieving a combination of chosen grid service applications or benefits, called use cases, through a hierarchical dispatch order that prioritizes long-term commitments over shorter ones and optimizes for storage system value across services of equivalent priority. Outputs include financial, technical and service-specific dispatch results over the defined technology lifetime. ESVT is unique among energy storage cost-effectiveness tools, due to its specific focus on energy storage and its time-series simulation capability[71]. All underlying databases, models, financial and performance equations are identical to those embedded in ESVT V4.0 and can be found in Akhil et al[71].

Table 2-2 provides an example of typical parameters provided for a 40MWHR Li-ion Battery ES project. All values used in this study are referenced in section 2.4.

Table 2-2: Typical Technology Input Parameters using the 10MW 4Hr Li ion Battery as an Example

Technology	Li-ion Battery [72, 73]	
Configuration	Capacity (MW)	10
	Duration (Hr)	4
	Technology Lifetime (yrs)	15
Performance	Battery Lifetime (yrs)	10
	Roundtrip Efficiency (%)	85%
	Max Depth of Discharge (DoD)	80%
Cost	Capital Cost ($/kWh) in 2016	640 CAD
	Variable O&M Cost ($/MWh)	2.70 CAD
	Fixed O&M Cost ($/kW-yr)	5.70 CAD
	Battery Replacement Cost in 2016 ($/kWh)	350 CAD
	Battery Replacement Cost Reduction	11% per year

To estimate Energy Market hourly prices for 2018, historical hourly prices from 2016 were multiplied by the ratio of 2018 forecast, to 2016 historical, average annual prices. Table 2-3 provides typical inputs needed to calculate the year-to-year value of each market service, using the Energy Market as an example.

Table 2-3: Typical Market Input Parameters using an Estimate AB's Energy Market in 2018 as an Example

Input	Units	Value	Format
Energy Prices	CAD/MWh	Alberta, 2016	8760 File
2016 Historical Average	CAD/MWh	18.00	Single Value
2018 Forecast Average	CAD/MWh	43.00	Single Value
2018:2016 Multiplier		2.389	Ratio

[71] (Navigant May 2014)

[72] Akhil, Huff and Currier 2015

[73] Lazard 2016, Lazard 2017

Table 2-4 illustrates the general financial parameters used in this analysis.

Table 2-4: Financial Assumptions using IPP as an Example, where IPP is an Independent Power Producer

Input	2030	2017
Financial Model	IPP	IPP
Discount Rate	10.8%	10.8%
Inflation Rate	0%	0%
Fed Taxes	15%	15%
Prov Taxes	12%	12%

Several studies[74] indicate that multiple revenue streams are required to result in net benefits with a reasonable payback period. ESVT can approximate profit maximizing decisions made by a grid asset owner/operator to obtain the total benefit of participating in multiple electricity markets, ancillary services and specific applications, while both considering the operational characteristics of the ES technology and following a generic North American ISO/RTO dispatch hierarchy[75]. The term "stackable" is used to mean that the costs and benefits are mutually exclusive, which avoids over-estimating and double counting benefits.

2.4 Model Inputs and Assumptions

The inputs and assumptions used in the model can broadly be broken into three categories as described in section 2.2 above.

2.4.1 Current Market Inputs

Benefits are defined in terms of what a single simple cycle CT or ES system operating on the AIES can provide in terms of AESO's current and planned markets and services.

[74] (Kaun June 2013, Lazard 2016, Lazard 2017)

[75] (Kaun June 2013, Electric Power Research Institute 2014)

Table 2-5 details the markets and services that the tool can model, and how they align with those in the AIES. The column "ESVT Potential Benefit" lists markets and services modelled by the tool. For each benefit, the AESO market or ancillary service that is currently, or might be, available is shown in column "AIES." Services included in this study are indicated by a "Y" (Yes) in the column "Scope". Customer Premise Services are considered Behind the Meter and out of project scope, marked by an "N". Price and load data that were either provided by Alberta stakeholders or estimated for the markets and services are shown in the column "Data".

Table 2-5: Summary of Grid or Markets and Services Benefits Modelled by ESVT[76]

	ESVT Potential Benefits	AIES
Application / Grid Service	**System/Market Services**	
	System Electric Supply Capacity	Capacity Market (no longer planned for AB)
	Local Electric Supply Capacity	Capacity Market (no longer planned for AB)
	Electric Energy Time-Shift	Energy Market
	Frequency Regulation	OR: Regulating
	Synchronous Reserve	OR: Contingency, Spinning
	Asynchronous Reserve	OR: Contingency, Supplemental
	Black Start	Black Start
	n/a	Load Shed Services for Imports (LSSi)
	n/a	Dispatch Down Service (DDS)
	Transmission Services	
	Transmission Investment Deferral	Sub scenario
	Transmission Voltage Support	n/a
	Renewable Generation Shaping	n/a
	n/a	Transmission Must Run (TMR)
	Distribution Services	
	Distribution Investment Deferral	n/a
	Distribution Losses Reduction	n/a
	Distribution Voltage Support	n/a
	Distribution Voltage Support (PV Ramp)	n/a
	Customer Premise Services	
	Power Quality	n/a
	Power Reliability	n/a
	Retail TOU Energy Time-Shift	n/a
	Retail Demand Charge Management	n/a

[76] (Akhil, Huff, & Currier, 2015)

Table 2-5, local electric supply capacity was not analyzed because data for the estimated Capacity Market (no longer being planned) at the local supply constraint level were not available and no reasonable assumption could be made at the time of this report. Electric Energy Time Shift, or Energy Market, was modelled as shown in Table 2-3. Black start services were modelled using an assumption shown in Table 2-10 because Black Start data were also not available at the time of this report. LSSi, DDS and TMR are not included in the valuation model.

Alberta does not currently possess a market or service for voltage support, either at the distribution or transmission levels.

Table 2-5, transmission deferral and renewable generation shaping are both possible in Alberta, but only a sub scenario for transmission deferral was modelled based on Alberta stakeholder input and available data. That specific sub scenario is described in Table 2-14 and Table 2-15.

Distribution Services, denoted with ‘N’ in the “Data” column are not included in this report as Alberta stakeholder data were not yet available. Future studies or individual TEA analysis of these opportunities can be completed on a case by case basis.

Energy storage in Alberta, under the currently proposed AESO tariff, pays a fee when charging and discharging. The AESO current tariff charges for Demand Transmission Service (DTS) and Supply Transmission Service (STS) are not included in this section’s analysis.

In this analysis, the cost-benefit models where mapped to scenarios (or use cases) of services that are available on the AIES as shown in Table 2-6. Three scenarios were investigated: Combustion Turbine (CT), Energy Storage (ES) and Energy Storage with Transmission Deferral. Each of the three scenarios was evaluated twice: with and without the proposed capacity Market (no longer being planned). The scenario labels are shown in Table 2-6 as CT 1, CT 2, ES 1, ES 2, ES and TD 1, ES and TD 2 respectively.

Table 2-6: Matching TEA tool benefits to Alberta market services, and defining TEA use cases for CT, ES, and ES&TD

TEA	AESO	CT		ES		ES&TD	
Benefits	**Markets and Services**	**1**	**2**	**1**	**2**	**1**	**2**
System/Market Services							
System Electric Supply Capacity	Capacity Market (no longer planned in AB)		Y		Y		Y
Electric Energy Time-Shift	Energy Market	Y	Y	Y	Y	Y	Y
Frequency Regulation	OR: Regulating	Y	Y	Y	Y	Y	Y
Synchronous Reserve	OR: Contingency, Spinning	Y	Y	Y	Y	Y	Y
Asynchronous Reserve	OR: Contingency, Supplemental	Y	Y	Y	Y	Y	Y
Black Start	Black Start Services			Y	Y	Y	Y
Transmission Services							
Transmission Investment Deferral	-					Y	Y

The model simulates the ES unit for the given lifetime of the technology and holds inputs and selections constant during the simulation. Both current and future markets plus services were simulated, and therefore two separate simulations were completed for each scenario, both “1” without (current) and “2” with (future) the estimated capacity market (no longer being planned), and both span the initial study year to the end of lifetime of each CT or ES technology. Historical price and load data were used for those markets plus services, and when unavailable, estimates were used based on historical data from similar jurisdictions. The effects of CO_2 pricing are not included in Pillar 2 at a project level for reasons given in section 2.5, but are specifically addressed in both Pillar 1 and Pillar 3 as mentioned elsewhere.

2.4.1.1 Ancillary Services

Ancillary Services price and volume data were used for each of the individual Grid Services or Use Cases in Figure 2-6.[77] Where AB data were not available, because no market exists for these services, publicly available data from similar ISO/RTO's were used in order to estimate the possible benefits.

Table 2-7 through Table 2-9 provide the input values for price and volume data, which were calculated as averages of AESO's historical 2013 and 2016 values for Operating Reserves, 1-year hourly data. Automatic Generator Controls (AGC) are not considered in this analysis[78].

Table 2-7: Alberta Input Data for Operating Reserves: Regulating, or Frequency Regulation

Input	Units	Value	Format
Regulation Price	CAD/MW	Years 2013, 2016	Hourly
Market Type: Separate or Combined		Combined	
State of Charge Requirements	Minutes	60	Single Value
Max Market Award	MW	80	Single Value
AGC Signal Selection		None	N/A
Allow Load?	Y/N	Y	Single Value

Table 2-8: Alberta Input Data for Operating Reserve Contingency Spinning, or Synchronous/Spinning Reserves

Input	Units	Value	Format
Spin Price	CAD/MW	Years 2013, 2016	Hourly
Allow Load?	Y/N	N	Single Value
Max Market Award	MW	80	Single Value
Probability to Dispatch	%/Hr	0	Single Value

Table 2-9: Alberta Input Data for Operating Reserve Contingency Supplemental, or Asynchronous/Non-Spinning Reserves

Input	Units	Value	Format
Supplemental Price	CAD/MW	Years 2013, 2016	Hourly
Max Market Award	MW	80	Single Value
Probability to Dispatch	%/Hr	0.1%	Single Value

Table 2-10: Alberta Input Data for Black Start Services

Input	Units	Value	Format

[77] (AESO, Energy Market and Ancillary Services Discussion 2017, AESO, AESO Annual Market Statistics 2017b, AESO, 2016 Annual Market Statistics 2016)

[78] AESO, Energy Market and Ancillary Services Discussion 2017) (https://www.aeso.ca/market/ancillary-services/)

Black Start Value	CAD/kW-Year	2.00	Single Value

The Black Start value in Table 2-10 is an assumption based on the North America average and is preloaded ESVT 4.0 data[79].

2.4.1.2 Effect of Installed ES on Price and Load Data.

At the project level, the simulation does not take into account the effect of ES on system level price and load data as described above. The dynamic effect of aggregated ES units on pool price and load data could be significant and is accounted for at the system level in the production cost model performed in Pillar 1. Pillar 2 utilizes actual historical wholesale market electricity - pool prices, ancillary service price, and actual load data from AESO. This provides a constant baseline, and assumes that the presence of a single ES unit operating on the AIES is relatively insignificant. However, pool prices as well as ancillary service prices were increased based on load data and macroeconomic indicators such as inflation and fuel escalation rate inputs.

2.4.1.3 Demand Charges

DTS and STS charges are not included in Pillar 2's valuation model.

2.4.2 Future Market Inputs

2.4.2.1 Potential for a Capacity Market

A future capacity market was evaluated in this analysis by using historical Capacity Market prices for ISO/RTO jurisdictions[80]. As was noted in the preface to this report however, it was recently announced that AB would be an energy-only market going forward. The impacts to this analysis of including a future capacity market were estimated in the preface section.

The three ISO/RTOs that are the closest to a potential Capacity Market in AB are ISONE, NYISO and PJM. This study used public historical Capacity Market prices from the three ISO's, converted to CAD[81,82], and calculated a weighted average based on the number of years each market has been operating. For an estimated AB Capacity Market, an approximate System Capacity Value of 62.81 CAD/kW-Year was used. In addition, AESO-specified capacity market participants would have been required to have a duration of at least four hours. All ES technologies studied have durations of at least four hours, except for the 10MW 2Hr Li-ion battery. This latter is participating in the supply capacity market as a 5MW 4Hr Li-ion battery.

It was expected that the introduction of a capacity market would not result in any added costs to end consumers. Therefore, energy market prices would be reduced by the introduction of a capacity market. In Pillar 2, the Capacity Market prices were estimated from other markets, but a corresponding reduction in energy market prices was not integrated in this analysis for simplicity. The results may overestimate the combined economic benefits and are considered an upper bound.

Table 2-11: Alberta Input Data for an Estimate of a Capacity Market, or System Supply Capacity

[79] (Electric Power Research Institute 2014, Akhil, Huff and Currier 2015)

[80](Charles River Associates 2017, EPRI 2015, AESO, Energy Market and Ancillary Services Discussion 2017)

[81] (Bank of Canada (up to April 28 2017) 2018)

[82] (Bank of Canada (from Jan 1 2017 forward) 2018)

Input	Units	Value	Format
Load Data	MW	2016 AIL	Hourly
System Capacity Value	CAD/kW-year	62.81	Single Value
Cost of New Entry (CONE)	CAD/kW-year	90.50	Single Value
Years Until Resource Balance Year	Years	10	Single Value
Min Capacity Duration	Hours	4	Single Value
Prob to Dispatch in Capacity Hours	%	100	Single Value
# of Capacity Hours per Year	Hours	130	Single Value

In Table 2-11, The System Capacity value is calculated from historical PJM, NYISO and ISONE data[83], and Years until Resource Balance Year is assumed based on estimated Capacity Market duration over study period.

2.4.2.2 Transmission Deferral

With the addition of several GW of wind capacity, primarily in central and south Alberta, three possible locations were identified where existing transmission infrastructure may not be able to deliver all of the additional wind capacity. The Pillar 2 analysis made approximations using the TEA tool to simulate how ES could defer transmission investment, and if so, by how many years, and provide an estimate of the financial benefit. Note that the transmission deferral sub scenario at the project ES level is different than that at the grid or system level discussed in Pillar 1. Locations and transmission approximations are summarized in Table 2-12 based on public data from AESO and the Regional Electricity Cooperation and Strategic Infrastructure initiative (RECSI)[84]. Actual Price and Load inputs used for the Transmission Deferral TEA simulation are shown in Table 2-13.

Table 2-12: Data for Transmission Deferral Sub Scenario

Line	Name	RECSI ES (Duschensne, 2017) Location	Est Load Growth / %	Est Cost / $
1	Chapel Rock to Pincher Creek	Goose Lake	5.75%	455 M
2	Tinchebray-Gaetz	Cordel	4.47%	578 M
3	PENV	N. Lethbridge	4.14%	242 M
AVG			**4.82%**	**425 M**
Total			**10.19%**	**1275 M**

In Table 2-13, the load data are based on 2008 data from the Pan Canadian Wind Integration Study (PCWIS) Alberta 5% Business As Usual (BAU) scenario averaged and then parsed into hourly values[85]. Maximum 2017 base year wind generation peak was 1431MW from the PCWIS data. For other Input values, there is an option to install modular ES units at regular time intervals. Based on feedback received from Alberta stakeholders, the Transmission Deferral sub scenario is evaluated as a single, non-modular ES. Maximum Years of Deferral was set

[83] Charles River Associates 2017

[84] (Market Updates Alberta Electric System Operator n.d.)

[85] Canadian Wind Energy Association (CanWEA) 2008

to be the same as an ES technology lifetime of 40 years for CAES or 60 years for P-Hydro. Load Target is the percent of base year maximum peak load required by the ES unit to supply.

Table 2-13: Alberta Input Data for Transmission Deferral Sub Scenario

Input	Units	Value	Format
Load Data	MW	PCWIS 2008	Hourly
Modular Installation	Y/N	N	Single Value
Maximum Years of Deferral	Years	40, 60	Single Value
Transmission Load Growth	%/Year	4.82%	Single Value
Load Target	%	101%	Single Value
Transmission Upgrade Cost	CAD	$425M	Single Value

An average value for all three potential transmission lines was used to make TEA simulation results more clear. To simulate the Transmission Deferral sub scenario, 2008 hourly wind generation in MW for Alberta's 1700MW of installed capacity was used[86]. Transmission line load growth was estimated by calculating the Compounded Annual Growth Rate (CAGR) in nameplate wind generating capacity from 1700MW in 2017 to 6000MW in 2030 using the same base year production profile. An estimated average wind capacity growth of 4.82% was used. Finally, the three estimated transmission lines costs were averaged to $425M each.

The transmission deferral simulations for the sub scenario estimated the amount of the maximum base year peak (in MW) a single ES technology can avoid by multiplying the growth rate by that maximum base year peak. That maximum was 1431MW multiplied by 4.82% to give 69MW of growth in year 1 of the study, which ES must be able to absorb. Therefore, if the maximum capacity or rated power of ES is less than approximately 69MW, there is no transmission deferral. For this reason, the 10MW Li-ion batteries could not provide transmission deferral. As Li-ion batteries with capacities of 100MW or more are presently being deployed, this study could only repeat transmission deferral calculations once data for commercial Li-ion ES systems of 100MW or more become available. Thus, based on current capacities and durations calculations, only CAES and P-Hydro were simulated in the present transmission deferral sub scenario.

Note the current regulatory framework in Alberta doesn't allow a transmission deferral asset to both sell electricity in the Energy Market and be a regulated transmission asset. The sub scenario shows what is possible if future regulatory changes are made.

2.4.3 Technology Inputs

2.4.3.1 Treatment of Technology Options

In order to compare multiple ES technologies, the main technical attributes such as cost, performance, and lifetime data were obtained from actual suppliers with consistent multi-year reports. Pillar 2 analysis used technology data for commercial assets or equipment at a TRL of 8 or 9 that a typical owner operator could purchase from a vendor. Based on Alberta Stakeholder input and available ES cost and performance data sets

[86] (GE Energy Consulting 2016)

from the U.S. DOE, three electricity to electricity (E2E) storage technologies were prioritized for analysis as summarized in Table 2-14[87].

Table 2-14: Technology Name, Lifetime (yrs), Power (MW) and Duration (Hr) of ES Systems and CT Studied. Source Data and Reference Details in Appendix VII.

CT	Energy Storage		
	Electrochemical	Mechanical	
	Battery		
Peaker (20 yrs)	Li-ion (15 yrs)	CAES (40 yrs)	P-Hydro (60 yrs)
50MW	10MW:2Hr	183MW:8Hr	280MW:8Hr
-	10MW:4Hr	183MW:26Hr	900MW:16Hr

With respect to data from the USDOE Energy Storage Handbook, the vendor survey is from 2010 and 2011. The cost curve data from Lazard's LCOS 2.0 was used to discount and extrapolate the respective ES costs from either 2010 or 2011 to 2016, when the ES unit would be purchased and installed. Finally, those discounted ES costs were converted from 2016 USD to 2016 CAD.

This study used the same data for natural gas prices that were used in Pillar 1[88], with 0% rate of inflation. Relevant Market Services and Financial input data are described in sections 2.4.2 and 2.4.4, respectively.

A detailed treatment of technology options is provided in Appendix VII.

2.4.3.2 ES Equipment Lifetime.

The number of years before stacks are replaced is used as an indication of ES lifetime and contains ES repair and maintenance. However, detailed battery degradation profiles were not included due to limited availability of the cycle life and durability data. In this iteration, 10 years was the number of years before stack replacement was required, which is based on an average of the 5 and 15 year values[89]. Two other inputs include battery stack replacement costs in $/kWh and the decrease in replacement costs as a % reduction per year[90]. Annual kWh degradation estimates are an output of the simulation[91].

No lead time is assumed from the time the project is approved, financed, site prepared, equipment installed and connected to the grid to the time it becomes operational. All ES technologies considered have a technology lifetime at least equal to or greater than the fourteen year horizon of the project. To account for different technology lifetimes, the resulting NPV's are multiplied by a simple ratio of project time horizon to actual technology lifetime.

[87] (Akhil, Huff and Currier 2015, Electric Power Research Institute 2014, Lazard 2016, Lazard 2017)
[88] (NGX 2018, Alberta Electric System Operator 2017)
[89] (Akhil, Huff and Currier 2015)
[90] (Lazard 2016)
[91] (Electric Power Research Institute 2014)

2.4.4 Financial Inputs

The final results from valuation analysis are represented in the form of several financial and economic outputs, optimization and simulation dispatch outputs, and the conversion of those time-series outputs into a financial model. This module incorporates key ownership and financing attributes, along with macroeconomic factors, to develop multiple project level outputs. Additionally, it performs a number of additional calculations for quick metrics and comparison that may be of interest to a user. The key inputs include ownership type, financing information, project term, inflation, discount rate, and project cost information, and key outputs include benefit to cost ratios, NPV, net cost of capacity, breakeven CAPEX, and project pro forma financials. The financial inputs and an illustrative output from the financial calculations and consistency with the common ES financial parameters are provided in Table 2-16, Table 2-17, Table 2-19, and Table 2-21.

2.4.4.1 Treatment of Financial Ownership Structure

The third area of input is financial ownership structure. This class of inputs focuses on the economics and details such as debt to equity ratios, tax rates, and regulatory incentives, which are key to completing the cost benefit analysis. Possible ownership types are listed in Table 2-15.

Table 2-15: Possible Ownership Types

Ownership Type
Investor Owned Utility (IOU)
Publically Owned Utility / Municipality Owned (POU/Muni)
Independent Power Producer (IPP)
Co-Operative (Co-Op)
Residential Customer
Customized or User Input

Given that Alberta is a deregulated market, and the project scope is in front of the meter, an Independent Power Producer (IPP) was chosen as the ownership structure. Details for the IPP ownership structure are shown in Table 2-16. Information was taken from public finance and tax data for Alberta and other published sources. Where applicable, economic inputs are aligned with assumptions in Pillar 1. Uniform ownership structure and details were used for all CT and ES simulations.

Table 2-16: IPP Financial Inputs

Financing Inputs	Ownership Type	IPP
Tax Inputs[92]	% Debt	20%
	Debt Interest Rate	8.00%
	% Equity	80%
	After Tax Nominal WACC (Discount Rate)	10.80%
	Return on Equity	12%
	Federal Income Tax Rate	15%
	Provincial Income Tax Rate, AB	12%
	Property Tax Rate	1.23%

[92] AESO, 2017

	Modified Accelerated Cost Recovery System (MACRS) Term (Years)	15
	% of Capital Cost Eligible for Tax Credit	0%
Economic Inputs	Inflation Rate (%/Year)	0.00%
	Fuel Escalation Rate (%/Year)	1.73%
Non-Tax Incentives	$/kW Province or Local Rebate ($/kW)	0.00
	$/kW Province or Local Rebate 2 ($/kW)	0.00
Technology Lifetime	CT (Years)	20
	Lithium-Ion Battery or Li-ion (Years)	15
	Compressed Air Energy Storage or CAES (Years)	40
	Pumped Hydro or P-Hydro (Years)	60

2.4.4.2 Taxes and Incentives

In order to represent Canadian taxes paid, three levels of taxes were interpreted from U.S. based taxation to a Canadian based tax model. They are federal, provincial and property taxes. With respect to property tax rates, Alberta uses mill rates, which are the amount due per $1,000 CAD of taxable value. Taxable value is about 75% of the capital cost for power generation[93]. Solas Energy Consulting estimated the overall mill rate average for Alberta to be 12.2982 based on available 2016 non-residential municipal tax rates from Alberta Municipal Affairs' Municipal Profiles[94,95]. This figure was rounded to 1.23% to align with ESVT's input format.

With respect to regulatory incentives, currently there are no Canadian federal or Alberta provincial regulatory incentives for ES. Federal tax credits and provincial local rebates could be modelled in the future once the data is available.

2.5 Model Assumptions and Implications

ESVT tool simulates the ES unit for the given lifetime of the technology and holds inputs and selections constant during the simulation. So for a market or grid service that could start after the initial study year, two simulations are run. One simulation is run without the grid service and one with, both from the initial study year to the end of that ES technology's lifetime.

The major limitations of the methodology are described in the StorageVET manual[96] in great detail and are summarized here. ESVT dispatch simulation can only operate on an hourly time step. It does not accept input data in any other format. It does not simulate state-of-charge effects of regulation activity and uses an optimization engine that limits the number of decision variables. This limits flexibility of service selection and time-step granularity. Treatment of multiple services is generally hindered in ESVT as it does not identify limiting storage performance factors in investment deferral use cases.

The employed model in Pillar 2 is a price taker model, in that it uses already determined market prices (or costs) as an input but does not determine how the resulting storage dispatch might affect those prices. Pillar 2 input prices could be historical prices from the wholesale market, or forecast prices. An interpretation of this

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[93] (Mah 2018)

[94] (Government of Alberta 2018)

[95] (Mah 2018)

[96] StorageVet Manual, 2018

approach is that the storage device is a very small or "marginal" resource and hence has a small, non-measurable impact on the market or power system. As a result, Pillar 2's model can overestimate market and services revenues if demand is limited, like Operating Reserves: Regulating or Frequency Regulation, and those results should be treated as an upper bound. For the same reason that it does not model impacts on market prices, it also does not model effects of the storage system on exogenous loads, or other elements within a transmission/distribution system, such as power flow or voltage control. Load effects, and interaction with transmission/distribution circuits are modelled as data time-series that are included as requirements for the storage system operation. ESVT and StorageVET™ do not model or simulate transient behavior at circuit level, such as frequency/voltage stability. The tool only models power and energy balances over time. Finally, the tool and models therein do not perform storage sizing endogenously. To overcome this shortcoming, sensitivity analyses can be performed that could allow for optimal sizing by evaluating a set of alternatives and providing information on their value.

Definition of ES Equipment Lifetime

No lead time is assumed from when the project is approved, financing provided, site prepared, equipment installed and connected to the grid, through to becoming operational. All ES technologies studied have a technology lifetime at least equal to if not greater than the fourteen year horizon of the project. To account for different technology lifetimes, the results are first shown for the actual technology lifetime, and then multiplied by a simple ratio of project time horizon to actual technology lifetime. The latter normalizes results to the same 14 year time horizon.

Effect of Emissions Calculations on Cost and Benefit Accuracy

In order to be stackable, ESVT valuation software cost and benefit outputs have to be mutually exclusive. Any calculation of emissions introduces the risk of double counting costs and benefits, which then makes ESVT outputs no longer stackable. Hence the impact of Green House Gas (GHG) emissions and effect of CO_2 pricing are not included in section 2 of the Alberta Chapter. They are covered in section 1 and specifically in the life cycle environmental impact assessment performed in section 3.

Markets, Services Modelled and Electricity Supply / Demand Costs

Markets and services or benefits modelled in ESVT are fixed categories based on what is common across Canadian and American ISO/RTO's and defined by the U.S. DOE, EPRI (Akhil, Huff and Currier 2015, Electric Power Research Institute 2014). Markets and services that were unique to Alberta, like LSSi and Transmission Must Run / Dispatch Down Service, weren't modelled in this section because they didn't fit into a common framework that can be used across Canadian jurisdictions and aligns with benefit categories outlined by U.S. DOE, EPRI. Demand Transmission Service (DTS) and Supply Transmission Service (STS) cost calculations are not included in this section, but they are described in section 1.

2.6 Simulation Results

2.6.1 Comparing Use Case and Sub Scenario Outputs

Given the ES technologies and grid service use cases from Table 2-6, 22 scenarios were developed that evaluate the benefits of three ES technologies relative to the available grid services. ES is separated into three ES technologies (Li-ion, CAES, Pumped Hydro), and further separated into two Li-ion, two CAES and two Pumped

Hydro Power and Duration categories, as well as a CT for a total of seven. Grid services are separated into two use cases, repeated only for CAES and P-Hydro ES in a sub bundle for a specific transmission deferral. Thus seven technologies in two use cases make fourteen simulations, plus four technologies in two sub scenarios for another eight simulations for a total of twenty-two simulations. Further detail on these scenarios is available in Appendix VIII.

Since neither CT nor Li-ion in the assumed configuration can provide transmission deferral due to CT's inherent technical limitations and Li-ion's small capacity rating, these scenarios are marked as 'n/a,' not applicable, in Table 2-17 below.

Cost-benefit simulation results for the CT and ES technologies are shown in Table 2-17. See Table 2-6 for Use Case or GS Bundle definitions.

Table 2-18 which corresponds to the three output formats described in Appendix VIII.

Table 2-17: TEA Simulation Results for CT and ES Technology NPV (CT revenues from Operating Reserves couldn't be included at the time of this report due to an unforeseen valuation tool error)

GS Bundle	Baseline	Energy Storage					
	CT (MW:hr)	Li ion (MW:hr)		CAES (MW:hr)		P-Hydro (MW:hr)	
	50:n/a	10:2	10:4	183:8	183:26	280:8	900:16
1	-$58,506,606	$14,763,611	$7,236,092	$90,288,291	$64,960,161	-$794,982,701	-$3,509,852,129
2	-$32,955,479	$15,787,628	$9,254,553	$136,639,044	$111,732,172	-$642,376,787	-$3,019,333,120
1 TD	n/a	n/a	n/a	$85,322,143	$85,091,413	-$736,092,210	-$3,480,496,383
2 TD	n/a	n/a	n/a	$114,433,356	$114,443,525	-$583,486,296	-$2,989,977,374

Based on NPV, both Li-ion and CAES ES technologies are deemed to be profitable using the assumptions defined above. CAES is the most profitable at 183MW 8Hr in GS 2, which includes an estimate of the 2021 Capacity Market. The largest loss was for 900MW 16Hr P-Hydro ES, likely because its large capacity and duration weren't required by Alberta's markets and services. The high capital costs, and long lifetime of 60 years, at a return on equity of 12%, accrued faster than revenues from markets and services benefits. The CT also showed a loss due to limitations in the TEA simulation in modelling of the Operating Reserves, where limited possible benefits or revenue streams were captured. This modeling limitation didn't affect ES simulations. Figure 2-2 illustrates NPV values.

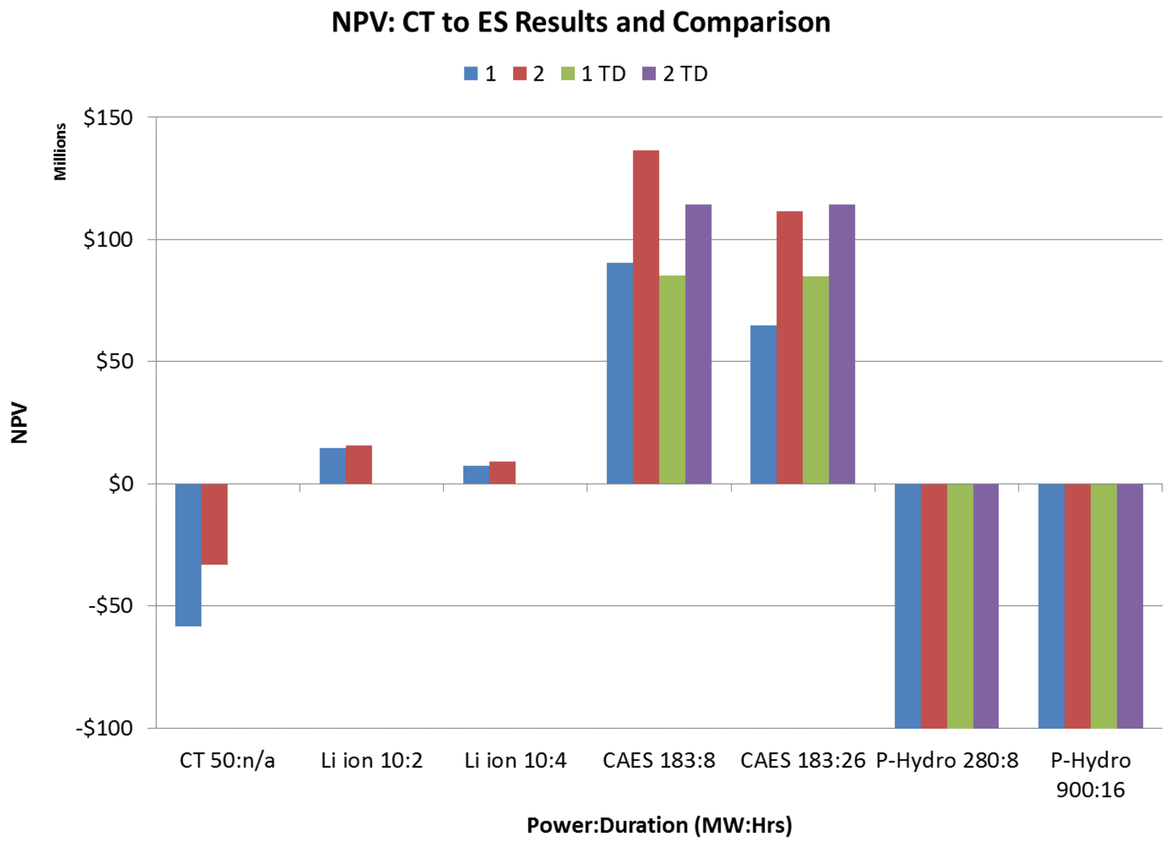

Figure 2-1: Simulation Results for CT and ES Technology NPV (y-axis Truncated to -$100M)

There are two conclusions from Table 2-17 and Figure 2-1 above. First, participation in the estimate of the 2021 Capacity Market increased NPV for all technologies. The actual NPV however, could be lower as described in section 2.4.2.1. Second, the Transmission Deferral sub scenarios increased NPV for all CAES and P-Hydro technologies except for CAES 183MW 8Hr (details and explanation in Appendix X). Of note, CT revenues from Operating Reserves couldn't be included at the time of this report due to an unforeseen valuation tool error.

Table 2-18: TEA Simulation Results for CT and ES Technologies by (a) Cost Benefit, (b) Least Cost per MW and MWh, and (c) Maximum NPV per MW and MWh

GS Bundle	CT	Energy Storage					
	Peaker	Li-ion		CAES		P-Hydro	
	(MW:Hr)	(MW:Hr)		(MW:Hr)		(MW:Hr)	
	50:n/a	**10:2**	**10:4**	**183:8**	**183:26**	**280:8**	**900:16**
(a) Cost Benefit Ratio							
1	0.17	1.51	1.19	1.25	1.17	0.28	0.16
2	0.55	1.54	1.24	1.35	1.27	0.42	0.28
1 TD	n/a	n/a	n/a	1.25	1.23	0.33	0.17
2 TD	n/a	n/a	n/a	1.32	1.30	0.47	0.28
(b) 14 yr Least Cost per MW ($M)							
1	$0.99	$2.69	$3.54	$0.70	$0.74	$0.92	$1.08
2	$1.02	$2.74	$3.63	$0.74	$0.79	$0.92	$1.08
1 TD	n/a	n/a	n/a	$0.65	$0.72	$0.92	$1.08
2 TD	n/a	n/a	n/a	$0.68	$0.74	$0.92	$1.08
(b) 14 yr Least Cost per MWh ($M)							
1	n/a	$1.34	$0.88	$0.09	$0.03	$0.12	$0.07
2	n/a	$1.37	$0.91	$0.09	$0.03	$0.12	$0.07
1 TD	n/a	n/a	n/a	$0.08	$0.03	$0.12	$0.07
2 TD	n/a	n/a	n/a	$0.08	$0.03	$0.12	$0.07
(c) 14 yr Maximum NPV per MW ($M)							
1	$(0.82)	$1.38	$0.68	$0.17	$0.12	$(0.66)	$(0.91)
2	$(0.46)	$1.74	$0.86	$0.26	$0.21	$(0.54)	$(0.78)
1 TD	n/a	n/a	n/a	$0.16	$0.16	$(0.61)	$(0.90)
2 TD	n/a	n/a	n/a	$0.22	$0.22	$(0.49)	$(0.78)
(c) 14 yr Maximum NPV per MWh ($M)							
1	n/a	$0.69	$0.17	$0.02	$0.005	$(0.08)	$(0.06)
2	n/a	$0.74	$0.22	$0.03	$0.01	$(0.07)	$(0.05)
1 TD	n/a	n/a	n/a	$0.02	$0.01	$(0.08)	$(0.06)
2 TD	n/a	n/a	n/a	$0.03	$0.01	$(0.06)	$(0.05)

Table 2-18 compares NPV results from Table 2-17 with cost benefit and normalized perspectives to illustrate both the respective return on investment per MW, per 14 years in Millions of CAD ($M). A brief summary is shown below and a detailed description is provided in Appendix VIII.

Table 2-18 are shown again in the bar graphs in Figure 2-2, Figure 2-3, and Figure 2-4 for clarity.

a. Cost to benefit ratio over entire technology lifetime at given power and duration
   - Less than one is a loss, equal to one is break even, and greater than one is a profit
b. 14 year present value least cost: per MW and per MWh
   - The lower the cost the better
c. 14 year maximum NPV: per MW and per MWh
   - The higher the NPV the better

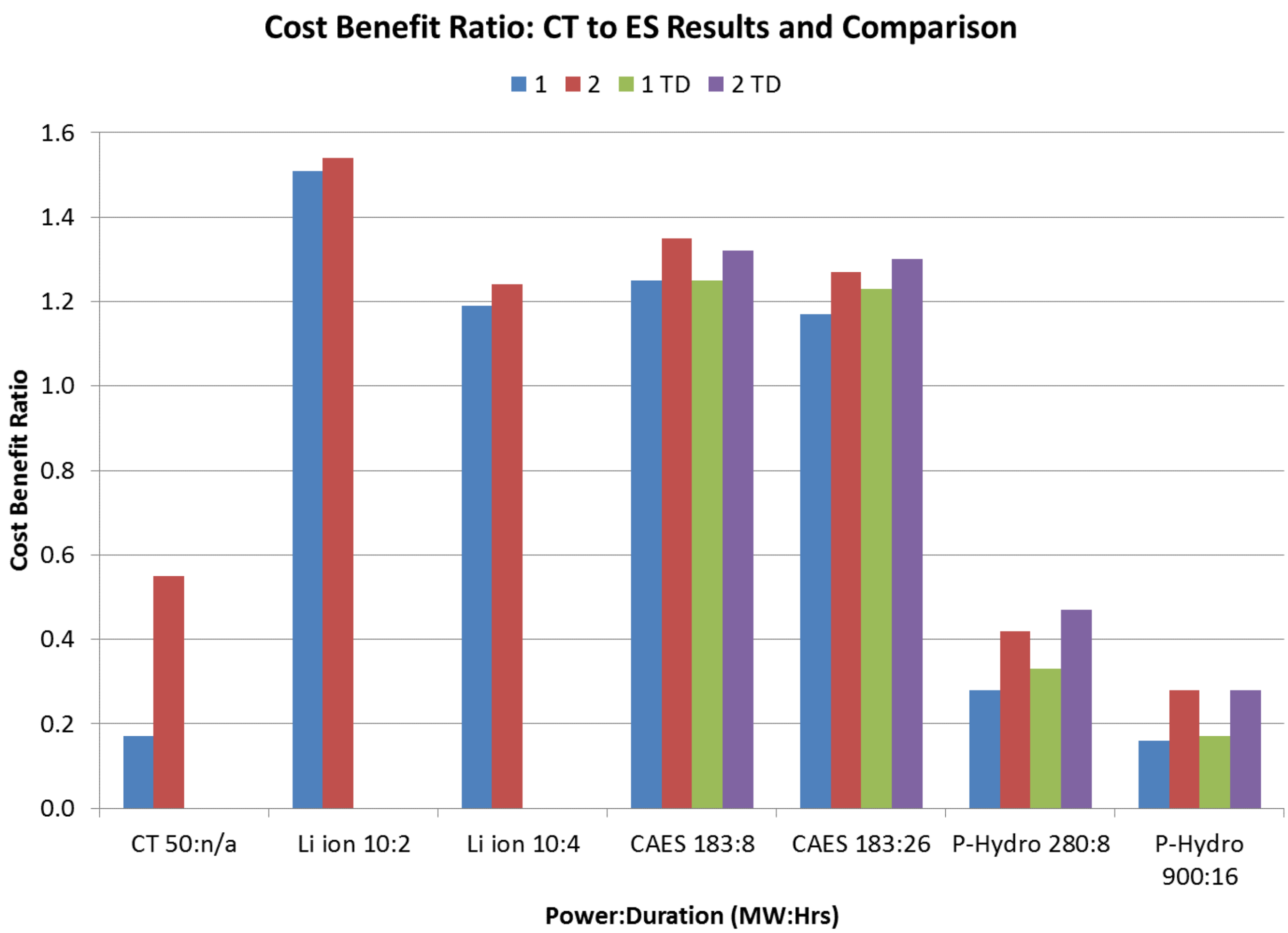

Figure 2-2: Simulation Output (a) Cost Benefit Ratios at Given Technology Lifetime, Capacity and Duration

In Figure 2-2, the technology options can clearly be assessed in terms of cost benefit ratio (break-even point is where the cost benefit ratio is equal to one; less than one is a loss, and greater than one is a profit). Cost benefit ratio minus one is the return on investment (ROI). While CAES has the highest NPV, the largest cost benefit ratio and ROI are for Li-ion ES with 10MW 2Hr at a maximum of 1.54 or 54% for GS bundle 2 (including an estimate of the 2021 Capacity Market). This is due to the combined effect of a proportionately higher Frequency Regulation revenue for Li-ion and a proportionately higher Operating Costs for CAES (see Table 2-20 and Table 2-22). Other trends remain similar for the estimate of the 2021 Capacity Market and for the transmission deferral sub scenario (Appendix X).

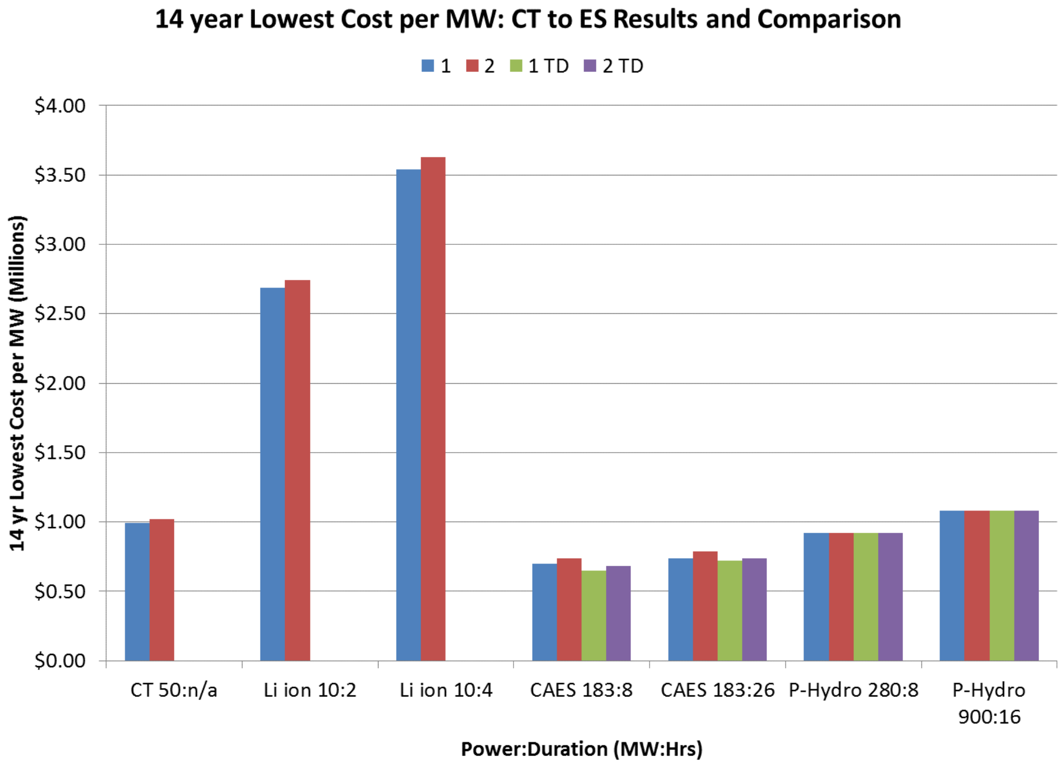

Figure 2-3: Simulation Output (b) Present Value Cost or Least Cost Normalized per MW per 14 Years of Study

In Figure 2-3, the least cost per MW per 14 years of study is attributed to CAES, whereas the highest cost is attributed to Li-ion battery ES. Normalized NPV results are shown in Figure 2-4.

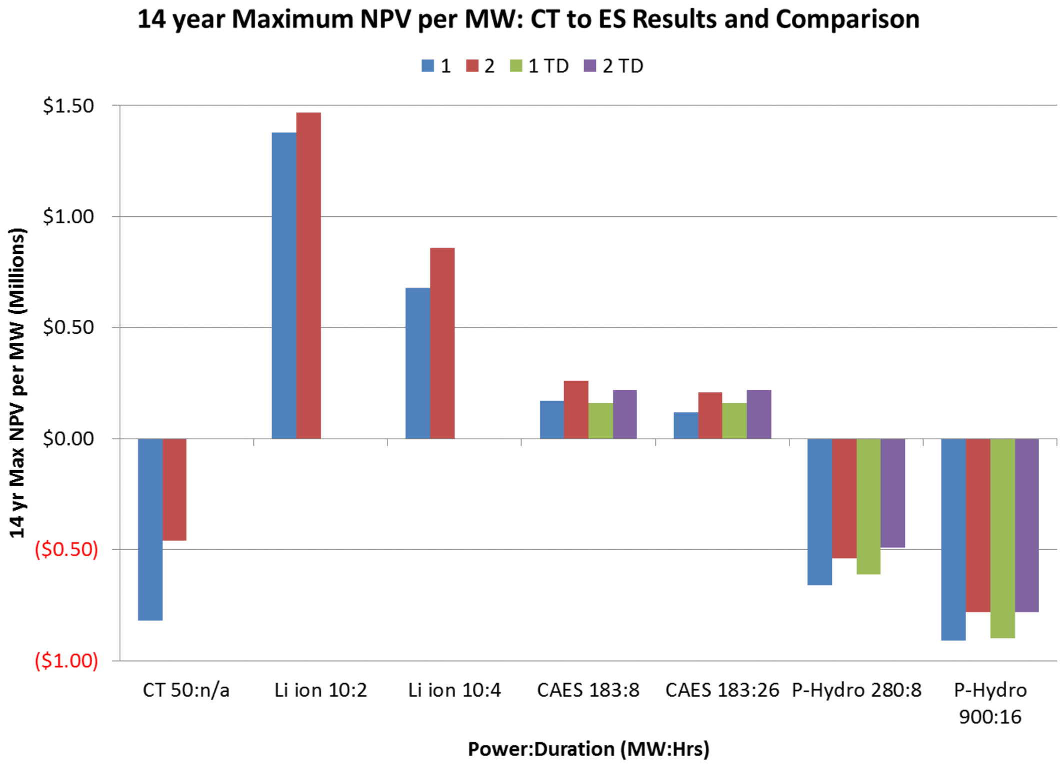

Figure 2-4: TEA Simulation Output (c) NPV Normalized per MW per 14 Years of Study

The highest NPV per MW per 14 years is shown for Li-ion ES technologies, specifically 10MW 2Hr Li-ion ES. CAES technologies also show a positive NPV. However there are two limitations affecting the current set of results. The first is with the CT module in the TEA simulation tool, and the second is with the availability of P-Hydro data sets for that tool. A separate factor affecting P-Hydro NPV is its high capital cost among ES technologies studied. First, given the CT's NPV increase from participation in the estimate of the 2021 Capacity Market, the CT could have a positive NPV once Operating Reserves (OR) are properly modelled by the TEA simulation tool. Limitations due to the AESO price and load data, and the cost-benefit model included in ESVT are currently preventing calculation of all OR for CT and in turn excluding associated revenues. All OR were properly modelled for ES technologies. Second, P-Hydro ES technologies show negative NPV's per MW per 14 years. Adding an estimate of the 2021 Capacity Market, and a specific Transmission Deferral sub scenario (Appendix X) increased NPV for both P-Hydro ES technologies. Here P-Hydro's negative NPV is a combination of availability of cost, performance and lifetime data and the technology's inherently high capital costs. The only two data sets available were for 280 and 900 MW P-Hydro ES systems. The 900MW P-Hydro ES system may be oversized for the given markets and services price and load data. However, the 280MW P-Hydro system is similar in capacity and duration to the 183MW 26Hr CAES ES System, but its capital cost is 3.4 times that of CAES'. Thus the inherent high capital cost of P-Hydro reduces its NPV. Given that P-Hydro is a mature technology with average capacities in the hundreds or thousands of MW, significant cost declines are unlikely. If data for smaller capacity P-Hydro data is available, then the simulations could be repeated and P-Hydro NPV could increase.

A more detailed explanation of those two limitations follows. First the CT module in the TEA tool wouldn't simulate any Operating Reserves (OR) when using actual AESO data. Again OR consist of high value services Frequency Regulation, Spinning and Non Spinning Reserves. The OR error uncovered in the CT module when using AESO data couldn't be resolved by the third party software provider in the time given for the AB Chapter. Second, both availability of detailed P-Hydro data (cost, performance and lifetime) is limited, and P-Hydro has among the highest capital costs. The only P-Hydro data sets that were both available and worked with the valuation software were for 280 MW and 900 MW systems. Compared to Pillar 1's base case results showing a potential for 1152MW and 4.74Hrs of ES, a 900MW 16Hr P-Hydro system with among the highest capital costs is unlikely to be profitable. It may be oversized. However, the 280MW 8Hr P-Hydro system can be compared to the 183MW 26Hr CAES system. The 280MW P-Hydro is roughly 1.5 times the capacity and 0.5 times the energy of the latter CAES system, but the capital cost of the 280 MW P-Hydro system is 3.4 times that of CAES. So it's unlikely the 280MW 8Hr P-Hydro system is oversized considering the 183MW 26Hr CAES system has a positive NPV. It's more likely the high capital cost of P-Hydro ES technologies is negatively impacting their NPV.

2.6.2 Summary of TEA Simulation Output Observations

Several observations can be made that are aligned with the following three main areas:

- Cost and Performance
- Markets and Services
- Financial

Regarding cost and performance, both ES technology costs and lifetime affect NPV. Longer technology lifetimes do not necessarily mean more time to recoup the investment. From a cost and performance point of view, major maintenance and repair intervals need to be considered. This holds for Li-ion ES and CAES as well as P-Hydro ES technologies. Expensive and multiple major maintenance costs impact the resulting benefits from CAES and P-Hydro, which leads to increasing operational costs compared to that of Li-ion where the stack was replaced once at year 10 (CT and ES maintenance costs available on request). ES technology life also impacts the cost of capital investment.

Regarding demand from markets and services, or price and load data, they are best described by the optimum sizing of technology capacity and duration. In the case of Li-ion ES, the capacity was insufficient to provide Transmission Deferral, and the duration for the 10MW 2Hr system was too short for participation in the estimated 2021 Capacity Market; therefore, that system had to participate as a 5MW 4Hr system. This did not affect NPV since Li-ion 10MW 2Hr is better suited for providing higher value Operating Reserves that are far more profitable than either the estimate of the Capacity Market or Transmission Deferral. For P-Hydro, their combined large capacities plus durations were unused and high capital costs drove up total costs significantly. In terms of duration, the 183MW 26Hr CAES system was able to provide the most benefit to Transmission Deferral, as well as more profitability to shorter duration Operating Reserve services (excluding Regulating or Frequency Regulation). Increasing duration introduces opportunity cost. ES technologies can capture more of the estimated Capacity Market, based on the above assumptions, and/or provide more Transmission Deferral, but at the expense of more lucrative shorter duration markets and services, while increasing capital costs.

Finally, regarding the third point, interest rates and debt to equity ratios combined with technology lifetime have a significant impact on the NPV of ES technologies. Given a debt to equity ratio of 20% to 80%, and a return on equity of 12%, the cost of capital (COC) or capital expenditure was consistently the largest of all costs (Table 2-21 and Table 2-22). This was more pronounced in the case of high capital cost intensive ES technologies with long lifetimes such as CAES and P-Hydro. In the case of P-Hydro, COC or capital expenditure outgrew revenue streams from all stackable benefits. The COC over the project lifetime must be minimized for any large capital expenditure long duration grid assets, including ES systems.

2.6.3 Selecting ES Technologies for Analysis of Stackable Present Value Costs and Benefits by Market and Services

After evaluating the results presented above, it is important to also compare ES options with CTs to assess the potential to improve upon conventional technology options. The ES technology with the highest cost benefit ratio and ROI was Li-ion 10MW 2Hr. The ES technology with the highest NPV was CAES 183MW 8Hr. First, CT, Li-ion and CAES were examined in Grid Service (GS) Bundle 2. Thereafter, the dispatch of the 10MW 2Hr Li-ion system was analyzed. The comparisons are summarized in the paragraphs below with details in Appendices IX and X. These two comparisons cover the first 2Hr versus 4Hr 10MW Li-ion in GS 2, the estimate of the 2021 Capacity Market, the second CAES 183MW 8Hr versus 26Hr GS 2, and the Transmission Deferral (TD) sub scenario. A Peaker plant or combustion turbine (CT) was to serve as a point of comparison to the ES technologies however, the Pillar 2 TEA model would not take OR into account for a CT when using historical grid data. This resulted in no OR revenues; therefore, the CT results cannot be used as a point of comparison to ES. Once resolved and OR revenues included, CT could be used as a baseline in future reports.

The benefits for CT, Li-ion 10MW 2Hr, CAES 183MW 8Hr and 26Hr in GS Bundle 2, are shown by benefit category in Table 2-19 in CAD and in Table 2-20 as percent of total benefits. The respective costs are shown in Table 2-21 in CAD and again in Table 2-22 as percent of total costs. Each stacked benefit and cost is then shown in the following figures for each technology and examined.

There are general trends for benefits and costs outlined here that are then examined in more detail for each technology in the figures. For ES technologies, Operating Reserves were the largest of benefits in Table 2-19 and Table 2-20. Within Operating Reserves, Regulating or Frequency Regulation was the largest benefit for Li-ion, and Contingency Supplemental was the largest for CAES. Qualitatively, this is the result of two factors. First, the price and load demand for Operating Reserves, combined with the operational response characteristics of the ES technology, meant fast acting ES with no minimum operating level, such as Li-ion can provide during short duration Frequency Regulation. Slower responding ES with minimum operating levels such as CAES provide Operating Reserves for a longer duration like Contingency Supplemental.

Table 2-19: CT and ES Present Value Benefits in CAD over Given Lifetimes for GS 2 with an Estimate of the 2021 Capacity Market

Benefits	CT (20yrs) 50MW	Li-ion (15yrs) 10MW 2Hr	CAES (40yrs) 183MW 8Hr	CAES (40yrs) 183MW 26Hr
Electricity Sales	$5,107,333	$1,166,556	$77,910,424	$77,970,907
Taxes (Refund)	$3,379,206	$ -	$ -	$ -
System Electric Supply Capacity	$31,133,326	$1,648,004	$69,534,815	$70,378,964
Frequency Regulation	n/a	$36,965,942	n/a	n/a
Synchronous Reserve (Spin)	n/a	$2,322,535	$71,552,852	$70,768,829
Non-synchronous Reserve (Non-spin)	n/a	$3,001,790	$299,634,332	$300,276,334
Black Start	n/a	n/a	$3,332,853	$3,332,853
Total	$39,619,864	$45,104,827	$521,965,276	$522,727,887

For Table 2-19 to Table 2-21 where the NPV is negative, taxes are refunded and appear as a benefit. The converse is true. Further, due to an error with the TEA simulation tool, Operating Reserves did not output for the CT. In addition, because CAES has a minimum operating level, and hence, a slow response, it cannot provide Operating Reserves Regulation, or Frequency Regulation. Lastly, a CT cannot provide Black Start (unless specially modified), and AESO stipulated Li-ion could not provide it either.

Table 2-20: CT and ES Present Value Benefits in % over Given Lifetimes for GS 2 with an Estimate of the 2021 Capacity Market

Benefits	CT (20yrs) 50MW	Li-ion (15yrs) 10MW 2Hr	CAES (40yrs) 183MW 8Hr	CAES (40yrs) 183MW 26Hr
Electricity Sales	13%	3%	15%	15%
Taxes (Refund)	9%	0%	0%	0%
System Electric Supply Capacity	79%	4%	13%	13%
Frequency Regulation	n/a	82%	n/a	n/a
Synchronous Reserve (Spin)	n/a	5%	14%	14%
Non-synchronous Reserve (Non-spin)	n/a	7%	57%	57%
Black Start	n/a	n/a	1%	1%
Total	100%	100%	100%	100%

Table 2-21: CT and ES Present Value Costs in CAD over Given Lifetimes for GS 2 with an Estimate of the 2021 Capacity Market

Costs	CT (20yrs) 50MW	Li-ion (15yrs) 10MW 2Hr	CAES (40yrs) 183MW 8Hr	CAES (40yrs) 183MW 26Hr
Taxes (Paid)	$ -	$8,131,550	$66,745,451	$61,586,860
Operating Costs	$14,086,629	$2,738,422	$142,413,430	$145,736,990
Financing Costs (Debt)	$9,510,933	$2,575,303	$27,259,075	$31,514,958
Capital Expenditure (Equity)	$48,977,781	$15,871,924	$148,908,276	$172,156,907
Total	$72,575,343	$29,317,199	$385,326,231	$410,995,715

Table 2-22: CT and ES Present Value Costs in % over Given Lifetimes for GS 2 with an Estimate of the 2021 Capacity Market

Costs	CT (20yrs) 50MW	Li-ion (15yrs) 10MW 2Hr	CAES (40yrs) 183MW 8Hr	CAES (40yrs) 183MW 26Hr
Taxes (Paid)	0%	28%	17%	15%
Operating Costs	19%	9%	37%	35%
Financing Costs (Debt)	13%	9%	7%	8%
Capital Expenditure (Equity)	67%	54%	39%	42%
Total	100%	100%	100%	100%

Costs shown in Table 2-21 and Table 2-22 use project finance terms (Akhil, Huff and Currier 2015). Taxes consist of federal and provincial income tax, property tax or mill rates, and include deduction for interest payments as well as depreciation. Operating Costs consist of charging costs, both fixed and variable operation and maintenance (O&M), any periodic replacement costs, and where applicable, housekeeping power and fuel costs, as well as start-up costs. Financing Costs or Debt include principal and debt interest payments. Finally, Capital Expenditure or Equity (COC) include the return of equity and shareholders' return on equity.

The largest cost for ES technologies in Table 2-21 and Table 2-22 was Capital Expenditure (CAPEX), or cost of capital in terms of accrued interest. This is because the IPP financial structure had a high Return on Equity (ROE) of 12%. However the second largest cost was different for Li-ion and CAES. For Li-ion, even though the stack was replaced at year 10 of the simulation, the Operating Cost was not significantly impacted. This is because the largest operating cost for Li-ion is stack replacement which only happens once in every 15 year lifespan. The latter can be significantly reduced due to the annually compounded sharp decrease in Li-ion stack cost compared to the start of the project. Regarding CAES, the second largest cost was Operating Cost (OPEX). Every four years there is a large Fixed Cost incurred per MW of capacity; therefore, the longer the technology lifespan, and the larger the capacity, the larger the Operating Costs for CAES.

Figure 2-5 to Figure 2-8 graphically show stacked present value cost and benefit associated with ownership and operation for the CT, Li-ion 10MW 2Hr, CAES 183MW 8Hr and 26Hr in GS Bundle 2.

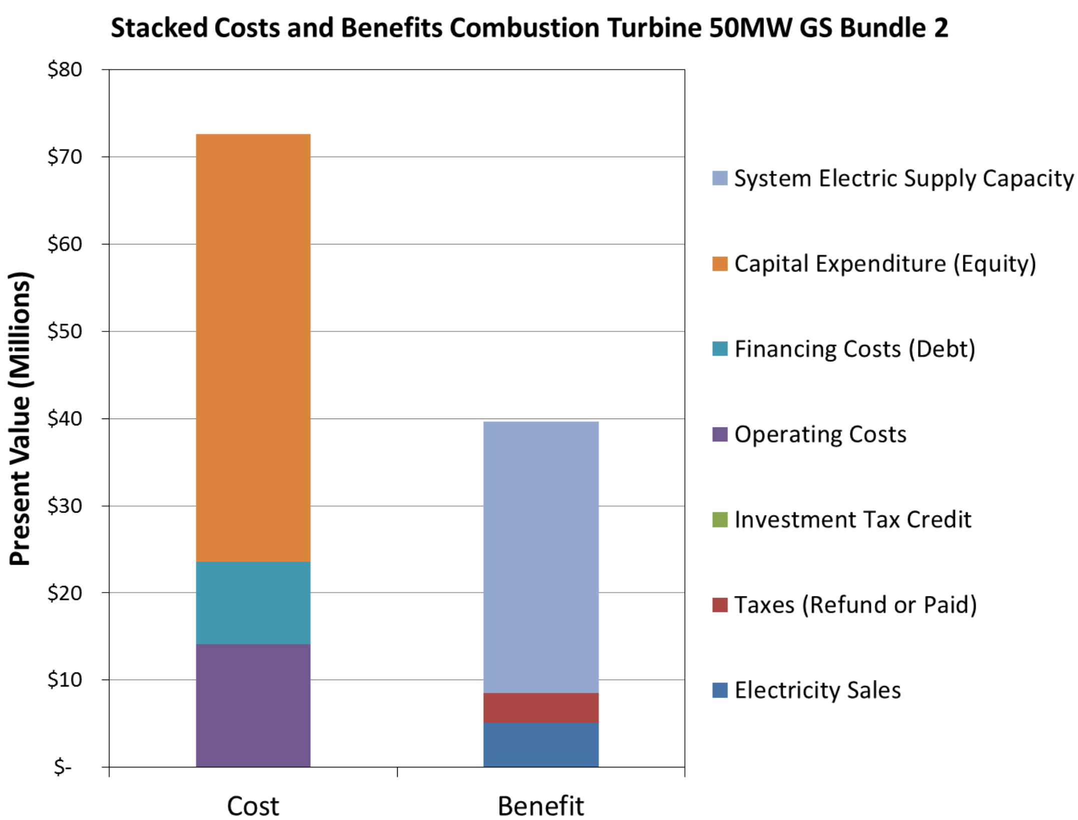

Figure 2-5: CT 50MW Stacked Costs and Benefits for GS 2 with an Estimate of the 2021 Capacity Market

A peaker plant or combustion turbine (CT) was to serve as a point of comparison to the ES technologies studied. However, due to an unforeseen error ESVT would not model OR for a CT when using historical grid data. Again, this resulted in no OR revenues and this error meant although CT results are shown, they can't be used as a point of comparison for ES. Figure 2-5, Table 2-19, Table 2-20, Table 2-21, and Table 2-22 show each present value cost and benefit associated with ownership and operation. The 50MW CT in GS 2 shows a present value benefit of $31.1M for System Electric Supply Capacity, or Capacity Market which is 79% of the total benefits. Electricity Sales, or the Energy Market, showed a present value benefit of $5.1M which is 13% of benefits with the remaining 9% as refunded taxes. Percentages may not add to 100% due to a rounding error.

As previously mentioned, OR couldn't be modelled for CT at this time. The CT can provide OR, and would gain significant benefits or revenue streams, which could make the CT profitable over its lifetime. OR for CT will be looked at again in the next version of the report together with other valuation tools. Switching to costs, the largest proportionately were the equity or capital expenditure at $49.0M or 67% followed by operating costs at $14.1M or 19%.

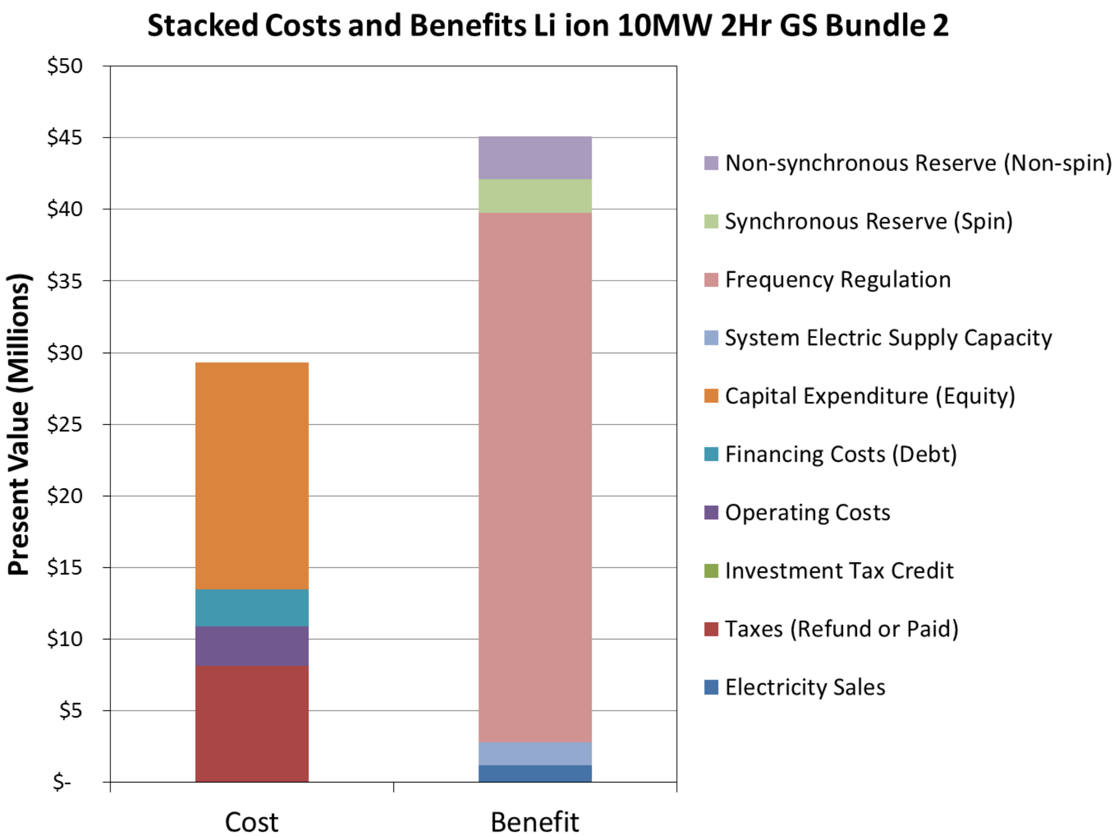

Figure 2-6: Li-ion 10MW 2Hr Stacked Costs and Benefits for GS 2 with an Estimate of the 2021 Capacity Market

In Figure 2-6, the Li-ion 10MW 2Hr case shows that the largest benefit was for OR, specifically Frequency Regulation or Regulating Reserve, at $37M or 82% of benefits, followed by non-synchronous reserves (Contingency: Supplemental) at $3M or 7%. Synchronous Reserves (Contingency: Spinning) were $2.3M or 5%, followed by System Electric Supply Capacity, or the estimated Capacity Market, at $1.6M or 4% of benefits. This is due to the fact that Li-ion battery technologies can provide OR Regulating Reserves quite well because they can respond quickly to frequency excursion signals from the AESO.

The largest cost is attributed to capital expenditure (CAPEX) at $15.9M or 54%, followed by Taxes Paid at $8.1M or 28%. Operating Costs were $2.7M or 9% even with the stack replacement cost at year 10 of the 15 year Li-ion technology lifetime. Stack replacement costs are lower than CAPEX or Taxes Paid, partly because of rapid Li-ion cost declines over the ten year stack lifetime.

The next analysis compares the 10MW 2Hr (providing capacity as 5MW 4Hr) and the 10MW 4Hr Li-ion batteries in an estimated 2021 Capacity Market. A detailed analysis, including annual service revenue bar charts over the ES technology's lifetime, is shown in Appendix IX. As expected, the 10MW 4Hr system produces nearly double the Supply Capacity benefits at a future value of $6.8M compared to the 10MW 2Hr system at a future value of $3.6M. What is notable is that the 10MW 4Hr system provides less Frequency Regulation or Operating Reserves and more of the other services than the 10MW 2Hr system, but the 10MW 4Hr system has a lower NPV at $9.3M compared to the 10MW 2Hr system's NPV of $15.8M. For an ES technology like Li-ion batteries, the longer duration increases capital costs more than revenues from Grid Services. The 2Hr system already captures the value for fast response in the highly lucrative Grid Services like Frequency Regulation.

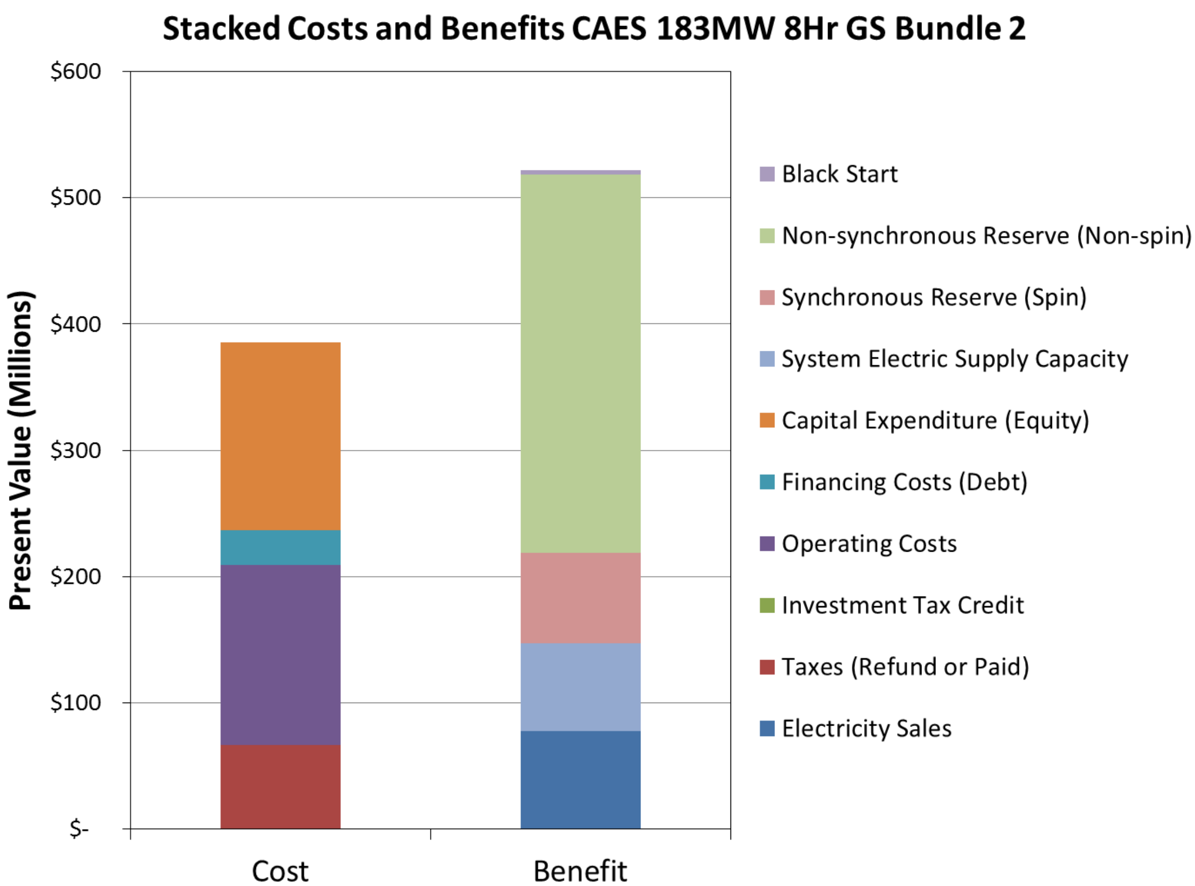

Figure 2-7: CAES 183MW 8Hr Stacked Costs and Benefits for GS 2 with an Estimate of the 2021 Capacity Market

In Figure 2-7, for CAES 183MW 8Hr, the largest benefit was for Non-synchronous Reserve, or OR, Contingency: Supplemental at $299.6M or 57% of benefits, followed by Electricity Sales or Energy Market at $77.9M or 15%. Frequency Regulation, or OR, Regulating Reserve was not included because the cost-benefit model does not optimize a technology with a minimum operating level, like the turbine within the CAES system. System Electric Supply Capacity, which is the value from the Capacity Market, was significant at $69.5M or 13% of benefits.

Capital expenditures of $148.9M or 39% and Operating expenditures of $142.4M or 37% were the two largest costs. The dominating costs for CAES technologies are a combination of high initial capital expenditures, expensive, regular periodic maintenance, a high return on equity of 12%, and long technology lifetimes. Operating expenditures for CAES are proportionately larger than for either Li-ion or CT. Here, the stacked benefits or multiple revenue streams from several markets and services still make the CAES technology profitable.

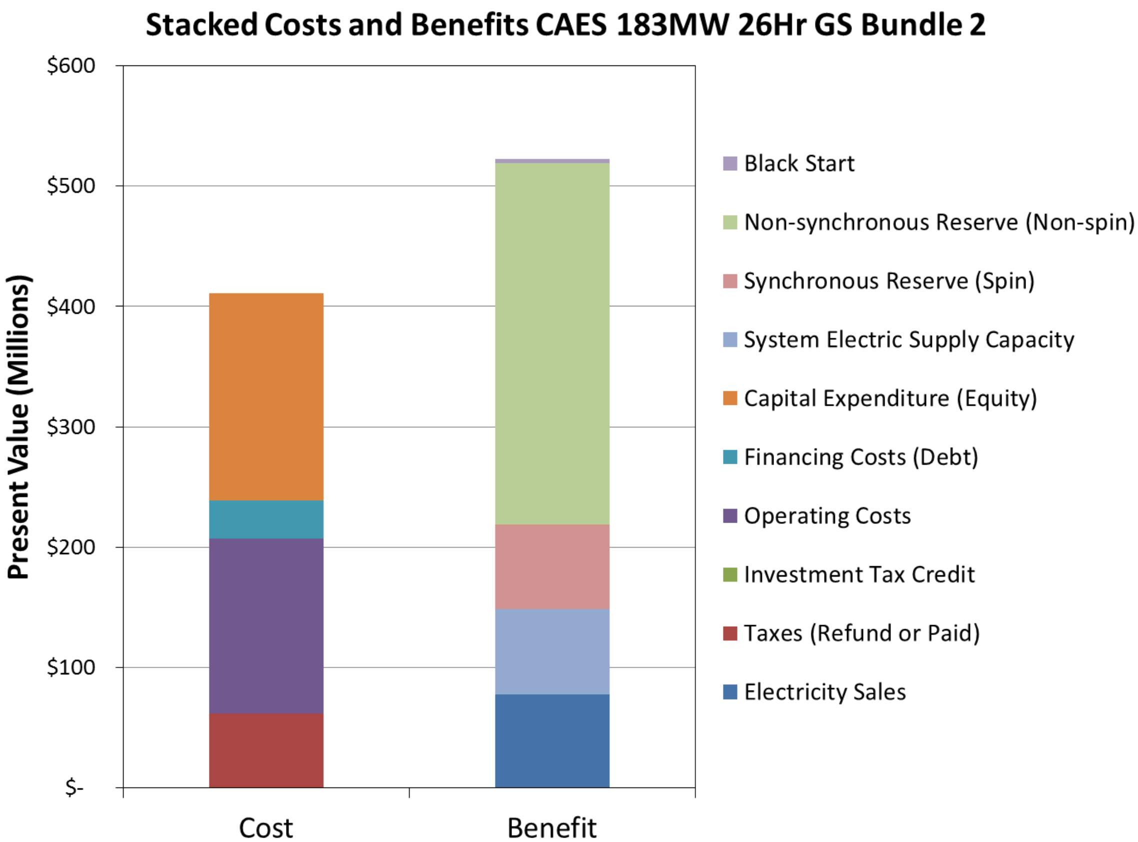

Figure 2-8: CAES 183MW 26Hr Stacked Costs and Benefits for GS 2 with an Estimate of the 2021 Capacity Market

In Figure 2-8, the same CAES technology has an increased duration from 8Hrs to 26Hrs. The incremental costs of underground storage for CAES technologies relative to other ES technologies are quite low. Total benefits increased slightly from $522M to $522.7M with increased storage; otherwise each market and service benefit was essentially the same. However, the costs increased significantly from $385M to $411M dominated by the increase in Capital Expenditures (equity). Therefore, although CAES 183MW 8Hr and 26Hr are both profitable, the 26Hr technology is not as profitable. This is because the markets and services price and load data do not require, or there is no need for, the extra 18Hrs of duration. The 8Hr to 26Hr comparision is summarized below for GS 2 with the Transmission Deferral sub scenario, and is discussed in more detail in Appendix X.

Switching to costs, the two largest are again Capital Expenditure and Operating Costs, the same trend seen for 8Hr CAES. Operating Costs are $145.7M and approximately $3.3M larger than those for 8Hr CAES which, relatively speaking, is not as large an increase as that for Capital Expenditure at $172.2M; $23.2M larger than that for 8Hr CAES. Again, although the incremental increase in capital costs for longer duration or increased underground storage is low, the increase in CAPEX at 12% over 40 years of technology lifetime must be overcome to make that extra storage or duration worthwhile.

The next analysis is comparing CAES 183MW 8Hr and 26Hr in GS 2, and including the Transmission Deferral (TD) sub scenario. That comparison is summarized here (with a detailed analysis and figures in Appendix X), and allows not only comparisons between the 8Hr and 26Hr CAES technologies, but also with and without Transmission Deferral. The added duration increased NPV for 26Hr CAES when providing Transmission Deferral at $114.4M with TD versus $111.7M without. However, adding TD to 8Hr CAES decreased NPV from $136.6M to $114.4M. This is for two reasons. First, capital costs increased for longer duration CAES more than benefits increased. Second, there is an opportunity cost when CAES provides TD at the expense of more lucrative short duration services like Operating Reserves. In summary, 8Hr CAES provides a higher NPV than 26Hr CAES, even though the latter shows that a specific application like Transmission Deferral is both operationally possible and more profitable with than without.

The final analysis is of ES technology dispatch operations on the AIES. Daily revenue and daily dispatch Hourly Dispatch and Cycle Count are examined for the 10MW 2Hr Li-ion ES.

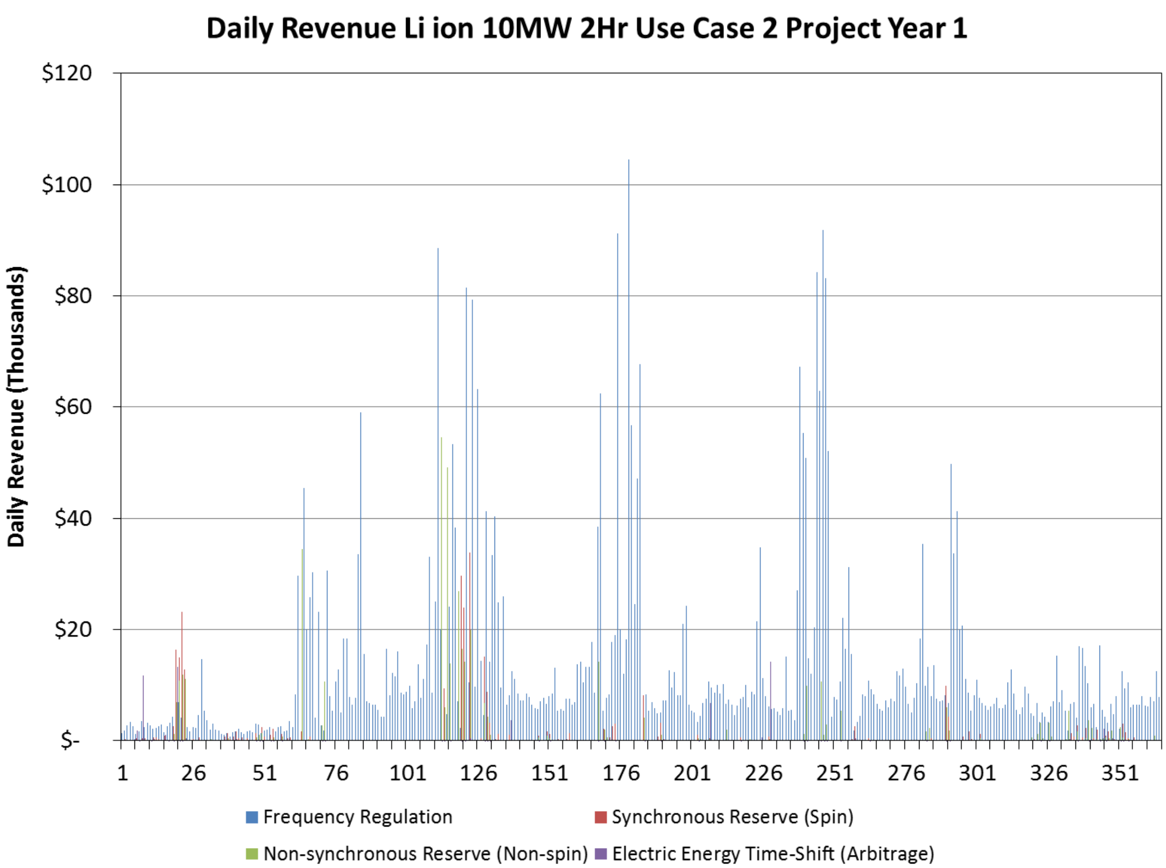

Figure 2-9: Li-ion 10MW 2Hr Project Year 1 Daily Revenue for GS 2 with an Estimate of the 2021 Capacity Market

Figure 2-9 shows Daily Revenue. Frequency Regulation or Operating Reserve: Regulating creates the largest revenues or benefits, followed by other Operating Reserves such as Synchronous or Spinning: Contingency and

Non-synchronous or Spinning: Supplemental. Revenues from Arbitrage or the Energy Market are the smallest and least frequent. Although the Energy Market may be the most lucrative for current market participants, for a hypothetical Li-ion battery with short duration, Operating Reserves could be more profitable than the Energy Market. The reason is that battery technologies such as Lithium-ion are well suited for fast response Grid Services such as Frequency Regulation. Supply Capacity, or the estimate of the 2021 Capacity Market, is not visible in Figure 2-9 as it is an annual revenue service and is explored in more detail in Appendix IX.

Table 2-23 and Figure 2-10 below show the number of cycles at each depth of discharge (DoD). The maximum DoD for both Li-ion ES technologies is 80%, hence no cycling is seen for DoD > 80%. Therefore, in the first project year, the 10MW 2Hr Li-ion battery cycled a total of 184 times with the bulk of those cycles in descending order at 40%, 20% and 3%. The 3% would correspond to sub hourly dispatches such as Operating Reserves. The 0% DoD would be rounded down for values less than 0.5% and again would correspond to Operating Reserves.

Table 2-23: Li-ion 10MW 2Hr Project Year 1 Cycle Count at each Depth of Discharge (DoD) for GS 2 with an Estimate of the 2021 Capacity Market.

DoD	0%	3%	10%	20%	30%	40%	50%	60%	70%	80%	100%	Total
Cycle Count	1	31	22	49	25	53	0	2	0	1	0	184

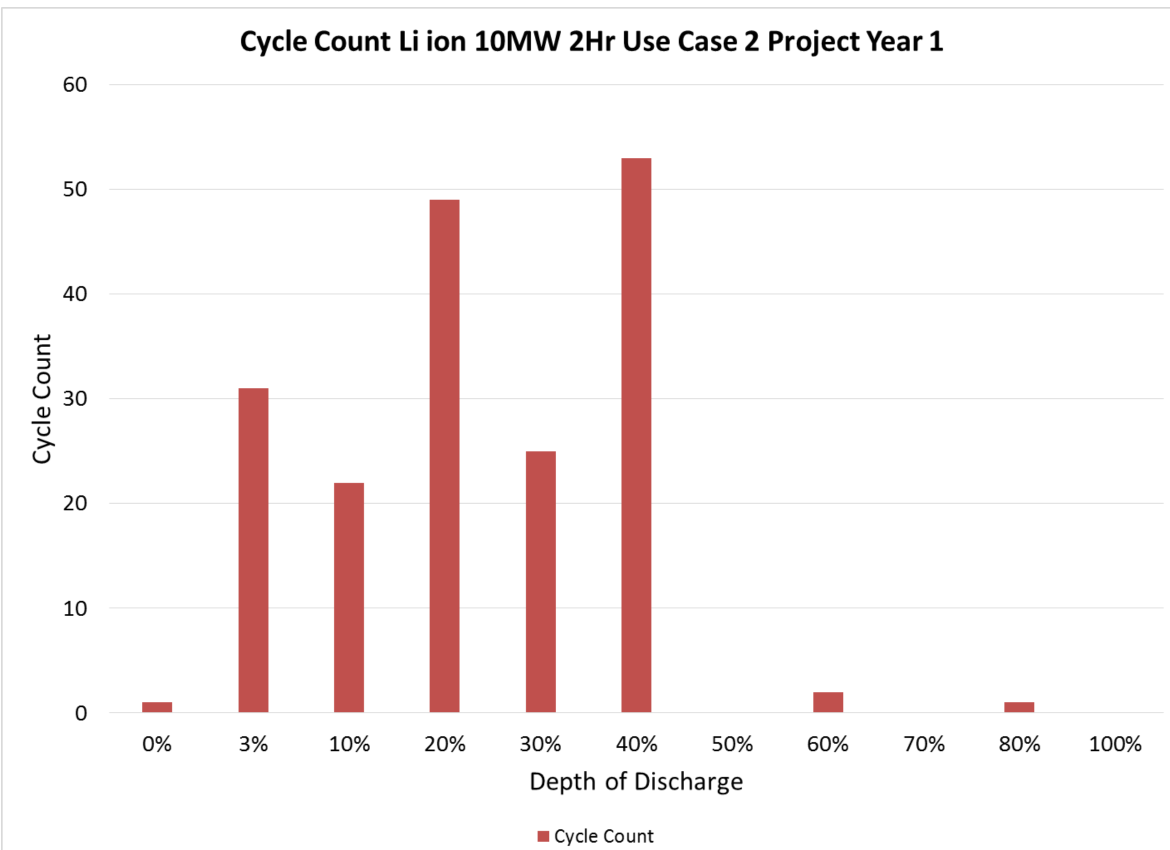

Figure 2-10: Li-ion 10MW 2Hr Project Year 1 Cycle Count at each Depth of Discharge (DoD) in GS 2 with an Estimate of the 2021 Capacity Market

The Li-ion battery is providing sub hourly Operating Reserves to maximize NPV, and when not providing those Grid Services for at least an hour or more, is providing Arbitrage or the Energy Market, and Supply Capacity, or the estimate of the 2021 Capacity Market. This trend of prioritizing short duration and high value benefits over long duration and low value ones is consistent for all the CT and ES technologies studied in Pillar 2. Again the model selects or bids into benefits (markets and services) while following a hierarchy based on a generic FERC based dispatch order.

2.6.4 The Impact of STS and DTS Rates for Distributed Energy Storage Systems

Demand Transmission Service (DTS) and Supply Transmission Services (STS) rates can apply to energy storage owners and operators at the generation and distributed energy storage sides. Pillar 2 has not taken into account the impact of these rates in the valuation. The current rates are proposed by AESO[97]. As a benchmark for energy storage, STS and DTS charges are at least $75/MW-month and $46/MW-month respectively, based on the current ISO Tariff. They are equivalent to a minimum of $0.9/kW-year and $0.6/kW-year for STS and DTS. Compared to the energy storage values and costs used in Pillar 1's capacity optimization (from $10/kW-yr for front of the meter to $78/kw-yr for energy arbitrage), charges of STS and DTS are much lower than the additional value that is modelled for the specific ES technologies. STS should be 0% to 7% of revenue depending upon where ES is located along the supply chain. Nevertheless, STS could be low if ES is located closer to load. Thus the impact of STS and DTS charges can be ignored in Pillar 1 and therefore is not being considered in Pillar 2.

2.7 Conclusions

The Energy Storage (ES) valuation analysis performed in this section evaluated the profitability and dispatch of individual ES technologies operating at a typical node on the Alberta Interconnected Electric System (AIES). This may differ from the analysis in Pillar 1. Although at the system level the AIES operation can be optimally designed to accept ES systems at certain nodes, with certain technology attributes and costs, it is not guaranteed that these deployments of individual storage technologies are equally economically or technically optimized at a project level. Therefore, several specific ES technologies were evaluated one at a time to identify the benefits, the overall economics of the ES deployment evaluated using project level metrics such as Net Present Value (NPV), and dispatch to the grid. Pillar 2 considered the economic benefits that were available for an individual ES technology operating on the AIES, as well as the potential for each ES technology to be dispatched to meet grid needs.

Three ES technologies were evaluated: Lithium-Ion (Li-ion); Compressed Air Energy Storage (CAES); and Pumped Hydro (P-Hydro). Results are based on given technology lifetimes first normalized to the 14 year study period and per MW to select the most profitable ones for further analysis. Evaluation results were categorized into profitability and dispatch. Second, profitability was further broken down into cost benefit ratio or Return on Investment (ROI), and Net Present Value (NPV) over the given technology lifetimes. The ROI was 1.54 or 54% for 15 year Li-ion 10MW 2Hr participating in both AESO's current Energy Market and Ancillary Services (except Load Shed Service for imports and Transmission Must Run / Dispatch Down Service) and the estimated (but no longer

[97] https://www.aeso.ca/assets/Uploads/Posted-July-12-2016-AESO-2017-General-Tariff-Application-2016-07-07-Presentation.pdf

planned) Capacity Market. The greatest NPV was $137M for 40 year ($48M normalized to the 14 year study period) CAES 183MW 8Hr participating in the same markets and services[98].

Three levers that impacted ROI and NPV profitability were technology, markets / services, and financial structure. Regarding technology, cost declines for Li-ion meant that a one-time stack replacement cost did not significantly impact overall profitability. However, longer technology lifetimes increase multiple major maintenance and repair costs for CAES and P-Hydro, which are mature technologies and do not have significant cost declines. Regarding markets / services, price and load data have a significant influence on choosing both ES technology response time and optimal capacity and duration ratings. Of the markets / services studied, proportionately, the largest benefits were from Operating Reserves (OR). It follows that ES technologies that could participate in one or more OR services captured the most benefits, contributing to profitability. OR Regulating dominated for fast response ES such as Li-ion, and OR Contingency Supplemental dominated for slower response ES such as CAES. All ES technologies participating in the estimated Capacity Market showed an increase in profitability, although not as large as for OR. Increasing CAES 183MW duration from 8Hrs to 26Hrs increased revenues within the Transmission Deferral sub scenario, but at the expense of overall NPV. Hence, there is an opportunity cost because the main value is in shorter duration services and longer ES duration does not support the increase in capital cost. Regarding financial structure, a 12% Return on Equity (ROE) made Capital Expenditures (Equity) the largest cost for the CT and ES technologies studied. A high ROE coupled with the longer lifetime, larger capacity and higher capital cost of P-Hydro ES technologies meant their Capital Expenditures (Equity) increased faster than their revenues.

Switching from profitability to analysis of ES dispatch, Daily Revenue of 10MW 2Hr Li-ion demonstrated multiple sub-hourly Grid Services such as OR can provide the largest revenues. However in the case of Li-ion Regulating Reserves they can pose the risk of significant wear and tear, possibly reducing stack lifetime. Regarding ES cycle counts and Depth of Discharge (DoD), the largest number of cycles were at DoD's that corresponded to sub-hourly dispatch (3% DoD) and at least hourly dispatch (20% and 40% DoD) for various Grid Services. These services are expected to be a combination of operating reserves, and participation in the Energy Market, as well as the Capacity Market, respectively. Although long duration markets and services have the highest usage of ES technology, that does not necessarily lead to the largest revenues.

[98] As stated in the Preface (pp. ii and iii), the policy changes that have taken effect since the analysis presented in this report was performed, will likely have an impact on the results presented here. Specifically, the policy changes are likely to lead to a decrease in NPV for ES projects (discussed in detail on p. iii).

3 Environmental and Socio-Economic Impact Assessment Pillar

As described in the Introduction section, the overall purpose of Pillar 3 is to evaluate the environmental and socio-economic impact of ES deployment in the Alberta electricity system by estimating the greenhouse gas (GHG) emissions and the number of jobs generated from 2017 to 2030 with and without ES.

3.1 Introduction to Pillar 3

A primary objective of Pillar 3 is to develop a systematic framework for the life cycle assessment (LCA) of stationary and large-scale ES systems. The first part of this section evaluates the environmental impact of ES technologies. The evaluation aims at providing a comprehensive environmental understanding of ES systems by identifying the major parameters that can improve their environmental sustainability, and provides detailed LCA data with updated life cycle emissions factors for ES systems, thereby increasing the robustness of the LCA results. Under this environmental life cycle analysis approach, this section quantifies the GHG emissions generated along the whole life cycle processes involved to manufacture, operate, and recycle Li-Ion battery ES and compressed air energy storage (CAES) systems. These were the two ES technologies that were analyzed due to limited life cycle inventory data available. Further study is recommended to perform a comparative analysis of GHG life cycle impact on ES systems for different stationary grid applications.

Two approaches to evaluate the environmental impacts of ES deployment in the Alberta electric grid were utilized: Overall GHG emissions at the grid level, and life cycle impact comparability between selected ES technologies, i.e. Li-ion and CAES. The aggregated GHG emissions for ES usage at the grid-level and the life cycle GHG emissions from manufacturing of ES technologies together comprised the system-level GHG emissions. The aggregated GHG emissions are based on changes in fossil fuel consumption over time as a result of ES integration in the grid and are obtained from Pillar 1’s simulation results. The life cycle GHG emissions from ES manufacturing uses a “cradle-to-gate” LCA approach and assumes that only these two technologies are deployed in the Alberta electricity system over the study horizon. For the ES technology GHG comparison, a “cradle-to-grave” LCA is used to calculate the environmental life cycle impact per technology where the GHG emissions from the operation phase are based on grid emission factors and round trip efficiencies.

The second part of this section evaluates the socio-economic impact in the Province of Alberta as a result of ES project implementation. Input-output economic models (IOM) were used to evaluate the economic impact of ES deployment. They track the changes of industrial outputs in the supply chain according to a shock (change) in the final demand of a given industry. The increase in the final output of a particular industry increases the demand on industries that supply goods and services, creating ripple effects throughout the economy. These effects are measured by input-output multipliers, which are estimated using the coefficients of IOM.

The socio-economic impact of ES deployment in Alberta is measured by quantifying the direct and indirect impact through the number of jobs created during the three main phases of typical ES projects: Planning and development, construction, and operation and maintenance. The direct impacts associated with the ES projects are also compared to those of renewable energy projects.

3.2 GHG Emissions Analysis

There has been debate on the value of ES with respect to GHG reduction. Due to round trip efficiencies, any individual ES project may have a negative GHG impact as measured on a project specific basis. Additionally, some critique the installation of new technology as having an overall negative impact on GHG emissions if the full life-cycle emissions are not considered. Therefore, the following section of the study aims to understand these overall impacts, and what potential benefits might accrue to the AIES with the introduction of ES.

3.2.1 Background

As outlined in Pillar 1, both the current GHG regulatory system, as well as the technology choices themselves necessarily impact the outcome of any GHG analysis. Therefore, the detailed treatment of each of these issues is outlined below.

3.2.1.1 Alberta's GHG Regulatory System

Aligning with global greenhouse gas emissions reduction efforts, the Province of Alberta in 2007 passed legislation to enable a carbon offset system in an attempt to curb GHG emissions and reduce its outstanding share of Canada's total GHG emissions. In 2017, the Alberta government revised the GHG regulatory system to include a carbon levy[99]. The major climate change legislation and regulations in Alberta are summarized in Appendix XI.

As described in section 1.2.1.2, on January 1, 2018, the Carbon Competitiveness Incentives Regulation (CCIR) came into effect under the provincial Climate Change and Emissions Management Act and replaced the former Specified Gas Emitters Regulation (SGER). Currently, this CCIR is applied to facilities in Alberta that have emitted more than 100,000 tonnes of CO_2e in a year since 2003, and/or any designated opted-in facility that competes against a facility regulated under the CCIR or has more than 50,000 tonnes of annual emissions, high emissions-intensity and/or trade exposure.

Under the CCIR, facilities are required to report their net emissions annually. Facilities that exceed the per unit output intensity for their industry sector must acquire offsets or pay the Carbon Levy. The output-based allocation regime is based on an assigned benchmark of emissions intensity for each product of a reporting facility. In the case of electricity generation facilities, the established benchmarks for 2018 to 2022 are 0.37, 0.37, 0.3663, 0.3626, and 0.3589 tonnes of CO_2 per MWh, respectively. The benchmark for 2023 and subsequent years is determined as the difference between the established benchmark for the previous year and 0.0037 tonnes of CO_2 per MWh[100].

Under the CCIR program, this is expected to cut emissions by 20 million tonnes by 2020, and 50 million tonnes by 2030 according to the Climate Leadership Plan. There are however three other alternative mechanisms allowed by the CCIR for large emitters who cannot achieve this target through improvements to their facilities.

- The first mechanism involves purchasing emissions offset credits. These offsets are emission reductions that can be generated by facilities in Alberta that are not subject to any climate regulation. Offsets must be created in accordance with Alberta's approved protocols, which identify the types of projects that can generate offsets and how to quantify the voluntary GHG reductions/removals for specific activities. Offset projects must be developed and implemented according to the ISO 14064-2 standard. As of 2018, there were 48 offset quantification protocols.

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[99] (Swallow and Goddard 2016)

[100] (Alberta 2017b)

- The second mechanism involves contributing to the Climate Change and Emissions Management (CCEM) Fund and obtaining a fund credit equivalent to 1 tonne of CO_2e. Through the Climate Leadership Plan, this money is collected to invest in clean energy research and technology and green infrastructure.
- The third mechanism involves being awarded with emission performance credits (EPC) expressed in tonnes of CO_2e by procuring EPCs from a facility whose emissions are below the industry target[101].

Under the Climate Leadership Plan, a carbon levy is imposed on purchases of all fossil fuels that produce GHG emissions when combusted, such as transportation and heating fuels. Each fuel type is taxed according to the amount of GHG emissions released when combusted. The levy is not applied directly to consumer purchases of electricity but rather to generators. Large final emitters are not charged for their heating fuel use under the carbon levy so long as they participate in the CCIR program. Additionally, natural gas produced and consumed on site by conventional oil and gas producers will be levied starting January 1, 2023 while that sector works to reduce methane emissions under the government's new joint initiative on methane reduction and verification[102].

Under the Climate Leadership Plan, the Government of Alberta declared plans to completely retire coal generation by 2030. The goal is to replace two-thirds of this electrical generation capacity with natural gas and one-third with renewable energy[103]. Under this GHG reduction perspective, the Government of Alberta tasked the Alberta Electrical System Operator (AESO) with developing and implementing the Renewable Electricity Program to support the development of 5,000MW of renewable electricity capacity by 2030[104].

The Government of Alberta has proposed to replace the CCIR with a Technology Innovation and Emissions Reduction (TIER) system for Alberta's large industrial emitters, with a target effective date of January 1, 2020.

Under the proposed system, facilities that emit more than 100,000 tonnes of carbon dioxide would have to reduce their emissions intensity by 10% compared to their average emissions between 2016 and 2018. The reduction requirement would increase by 1% per year, starting in 2021.

To meet the requirements of the proposed system, facilities would have the following options:

- Reduce their emissions
- Use credits from facilities that have met and exceeded their emission reduction targets
- Use emissions offsets from organizations that are not regulated by TIER, but have voluntarily reduced their emissions
- Pay into a TIER Fund[105]

[101] (Alberta 2017b, Canada 2017, Hannouf and Assefa 2017, Read 2014)
[102] (Alberta 2016, Alberta 2017a)
[103] (Alberta, Climate Leadership Plan 2018)
[104] (Canada 2017)
[105] (G. o. Alberta 2019)

3.2.1.2 Environmental Impact of ES Technologies

The role ES technologies could play in providing services to balance and maintain the reliability of electricity on the grid is increasingly important[106]. Alongside ES technologies, other suitable options such as improved operations, demand–side management, increased interconnectivity, and fast ramping supply are available measures for grid planners and electricity market regulators and policymakers to enable greater use of variable generation and increase grid flexibility into near-term operations and long-term planning[107].

Various studies discussed the role of ES grid applications to ensure an adequate grid flexiblity. Among these services are renewable electricty integration, economic value of co-optimized grid-scale ES investments, and increasing transmission utilization[108]. The many other grid services that ES can provide were discussed in detail in section 1.2.

In some instances, GHG reductions in Alberta are facilitated by the deployment of ES through reducing renewable curtailment as evaluated by Solas Energy Consulting (2017). In other services such as arbitrage, peaking capacity, regulating reserves, spinning reserve, transmission and distribution asset deferral, and frequency response among others, there is an increase in GHG emissions as determined by the same study. Solas Energy's study analyzed project level GHG emissions based on the principles behind Alberta offset protocols and the ISO 14064-2 methodology, for all 16 services that ES provides, for multiple technology types and locations of services. The current study provides a framework to calculate GHG emissions reductions at the project level in order to support participation in regulated and voluntary emissions trading schemes and public reporting[109]. A baseline emission rate was determined by calculating a grid displacement factor from Alberta Environment and Parks based on the grid intensity factors guidelines developed by World Resources Institute (2007). Currently, there are no existing GHG quantification protocols in Alberta that address GHG emissions reductions directly from energy storage projects[110].

The impact of ES deployment at the system level on GHG reductions has not been conclusively determined. Hittinger and Azevedo (2015) reported that emissions from the United States increased with deployment of bulk ES for energy arbitrage considering the existing grid mix; however, they did not consider prospective renewable energy additions. Lin et al. (2016) reported that ES application should be focused on regions with significant renewable energy curtailment and total emissions may increase or decrease depending upon the system configuration. This approach does not consider the other uses of ES outside of renewable energy integration.

Another important consideration, which has often been neglected in previous analyses, is the life cycle emissions quantification during manufacturing, recycling, and disposal of ES systems as part of the total GHG emissions due to ES deployment at the grid level. According to the ISO 14044[111], the LCA method provides a framework to evaluate GHG emissions or benefits under a supply chain perspective for a specific product over

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[106] (Few, Schmidt and Gambhir 2016)

[107] (Aggarwal and Orvis 2016, Denholm, Ela, et al. 2010)

[108] (Denholm and Sioshansi 2009, Denholm, Ela, et al. 2010, Roderick, Munoz and Watson 2016)

[109] (ISO 2006a)

[110] (Alberta 2008)

[111] (ISO 2006b)

its full life-cycle from raw materials extraction, processing, manufacturing, transportation, and operation through disposal (cradle-to-grave). LCA is a product life cycle approach that provides GHG emission quantification based on the processes used to manufacture and manage a product, as opposed to an offset approach which only quantifies emissions reductions during operation at project level.

Among the most relevant environmental management techniques, LCA can provide system boundaries and a functional equivalence as relevant elements to quantify GHG emissions, and perform comparative assertions between two or more alternative product systems[112]. LCA results are often used to measure environmental performance for comparison between different options on the market. For example, Unterreiner et al. (2016) analyzed the influence of using recycled materials for different battery technologies on the battery system's environmental impact.

Most LCA studies on batteries focus on their application in the automotive industry; however, there is a significant lack of specific LCAs for battery ES systems for stationary applications. Few LCA studies on ES systems take into account the operations phase of an ES system for evaluating overall GHG emissions. The operations phase is however unique as it charges and discharges from/to the electric grid. According to Hittinger et al. (2015), charging increases the electricity generation, increasing emissions from the grid, while discharging decreases the generation, decreasing emissions. Hiremath et al. (2015)'s LCA study on battery ES for stationary applications found that both emissions due to electricity losses from battery use and emissions from power-grid mix used to charge the batteries dominate battery life cycle impacts significantly, however the battery discharge effect on the grid emissions is not evaluated.

The two primary objectives of the Pillar 3 study are to evaluate the environmental impact of ES systems at the grid level and perform a comparative life cycle GHG impact analysis on ES technologies. The system level environmental impact is evaluated by quantifying the overall GHG emissions generated by ES technologies in the Alberta electricity system. Grid-level GHG emissions are calculated by adding GHG emissions from the ES manufacturing phase and net system GHG emissions from ES operation in the grid. The latter is obtained from Pillar 1's simulation model. Given that Pillar 1's simulation model outputs are based on an ES technology agnostic approach, the ES operations phase GHG emissions are aggregated values without a breakdown of GHG emissions by ES grid services. Moreover, it is assumed that two technology types, Li-ion battery and CAES systems, are deployed in the Alberta electricity system over the period of study. For the ES technologies comparison, a 'cradle-to-grave' LCA is used to calculate the environmental life cycle impact per technology while the GHG emissions from the operation phase are based on grid emission factors and round trip efficiencies.

3.2.2 Methodology

The overall methodology of GHG evaluation through LCA is shown in Figure 3-1. Consideration of the environmental impacts of all product stages and the cradle-to-grave impacts are performed under a standard LCA methodology framework[113]. The cradle-to-gate emissions include emissions from raw material production, components production, and ES product manufacturing. Further emissions occur during the ES product operations phase (charging and discharging) at the grid level and ES product recycling. The net system emissions from the ES operations phase are the sum of the increased and displaced emissions from the grid as a result of

[112] (Santero and Hendry 2016)

[113] (ISO 2006c, ISO 2006b)

overall ES charge/discharge cycles. The operations phase at the grid level is calculated by taking the difference of fossil fuel usage for the Benchmark Scenario compared to ES Capacity Scenario as evaluated in Pillar 1.

Pillar 3 also incorporates the differential charging and discharging for each ES technology by considering marginal emission factors depending upon current and prospective generation mixes to perform a comparative LCA of different ES technology types.

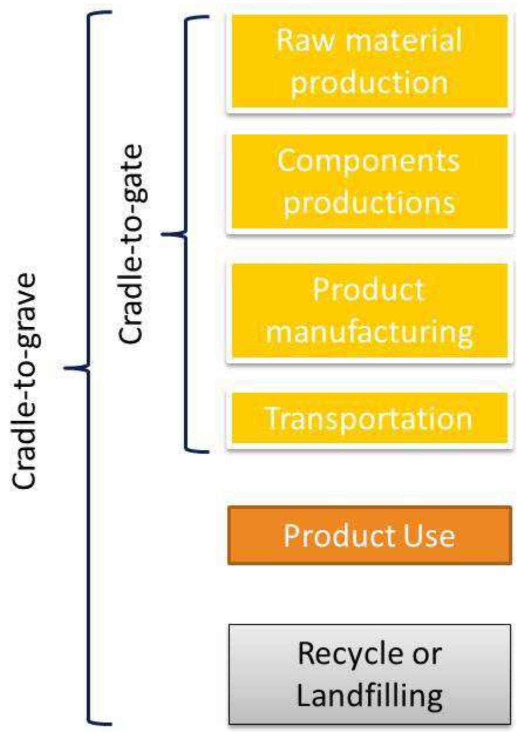


Figure 3-1: Overall GHG Emissions Estimation Methodology

3.2.2.1 Life Cycle Assessment (LCA) Phases

LCA is a method that provides a comprehensive view of impact categories across all stages of the life cycle of a product system from cradle-to-grave[114]. LCA is an environmental systems analysis tool that is applied for the evaluation of the potential environmental impacts and resources consumed during a product's life cycle, including raw material production, manufacturing, operations phase and waste management[115]. As shown in Figure 3-2, a typical LCA approach involves four stages:

1. ***Goal and scope definition***
2. ***Life cycle inventory (LCI) analysis, which includes quantifying flows of resources and environmental releases***
3. ***Impact assessment, which includes collection of impact categories and classification, collection of characterization and characterization methods, and the optional phases of normalization, grouping and weighting***

[114] (ISO 2006b)

[115] (Finnveden 2000, ISO 2006c)

4. ***Interpretation and evaluation of the robustness of the results***

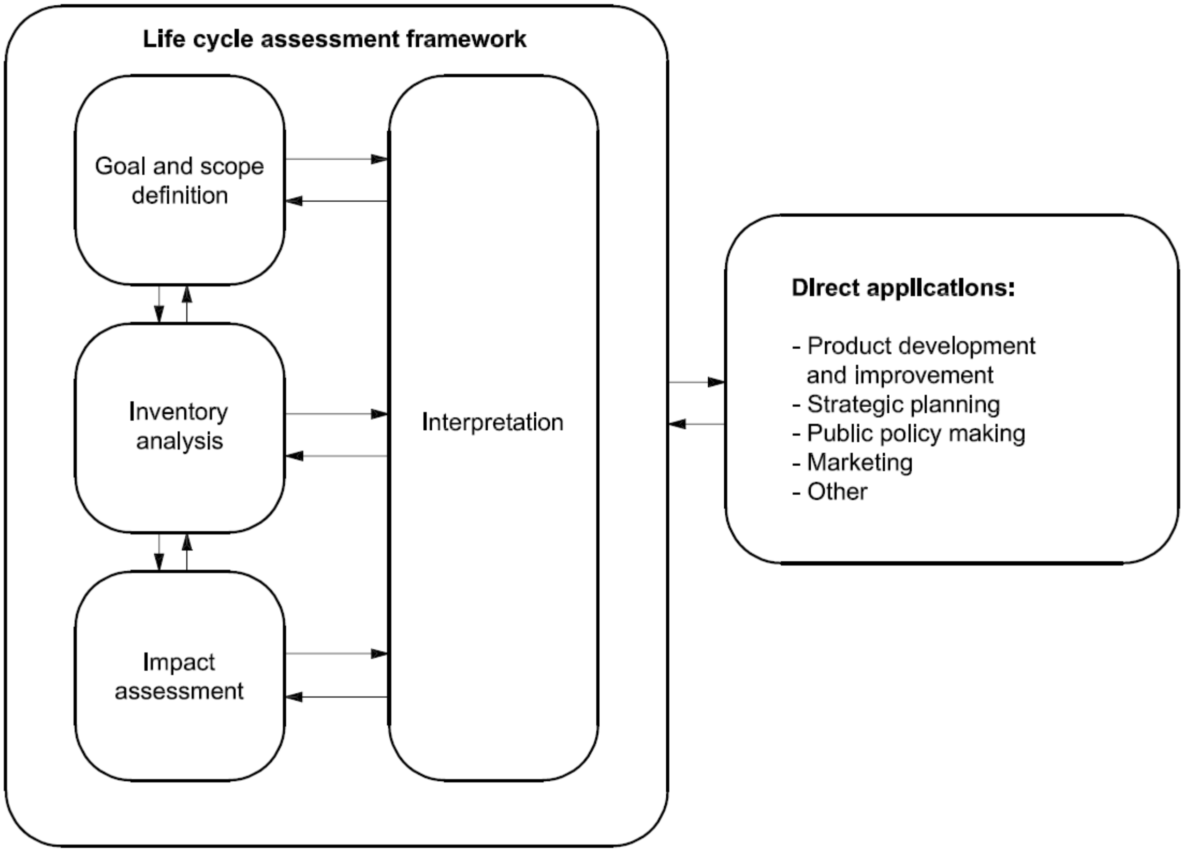


Figure 3-2: Main Phases of Life Cycle Assessment (ISO 2006c)

LCA is data-intensive and is typically performed with a mix of data sources of variable data quality. Several software packages are available for performing LCA studies, and a number of national and international databases are widely employed for performing the studies. The cradle-to-gate LCA study of Pillar 3 was performed using the LCA software SimaPro version 8.3.

3.2.3 Application of the Methodology

The main objective of this study was to assess the potential environmental impacts and benefits of applying Li-ion batteries and CAES as ES systems. Only these two technologies were analyzed since there are few LCA studies of ES technologies with complete and open LCI data to be modelled. In addition, Li-ion and CAES projects are of interest to stakeholders as these projects are listed in the AESO connection queue list.

3.2.3.1 Goal of the LCA Study

The goal of the LCA study was to assess the GHG emissions of Li-ion battery ES systems and CAES during their life cycle, including raw material production, manufacturing, use in the electric grid, and recycling (end of life). Given the considerable variation in the quality of cradle-to-gate LCI data and battery characteristic data available in the literature for the different battery types, Li-ion was the only battery type chosen for this LCA study. The LCI data for Li-ion used in this study were sourced from a very detailed open inventory[116].

[116] (Hiremath, Derendorf and Vogt 2015, Majeau-Bettez, Hawkins and Stromman 2011)

3.2.3.2 Scope of the Study

According to ISO 14044, the scope of an LCA study should define the studied product system, the function of the product system, the functional unit, allocation procedures (if any), types of impacts and life cycle impact assessment (LCIA) methodology, interpretation, data requirements, data quality requirements, limitations, and assumptions.

In this section, the LCA methodology is presented with application to Li-ion battery ES systems. Differences in the assumptions and input values for CAES systems are also provided.

3.2.3.2.1 Product System

The product systems of this LCA case study are a large-scale Li-ion battery pack used as a component of a Li-ion battery ES system and a CAES system used for stationary grid applications, i.e. to store and deliver electricity to the grid. Note that the life cycle emissions of other components of a Li-ion battery ES system will be estimated values based on qualitative assumptions from literature.

For the Li-ion battery pack product system, a cell chemistry of $LiFePO_4$ (LFP)/graphite was utilized. This chemistry was selected for this study due to its environmental affability, low cost, material availability, and cycling stability. Moreover, a combination of the graphite anode and the $LiFePO_4$ cathode have been determined to be reliable cell chemistries for ES applications because of their good cycling stability, energy density, and cost[117].

The mass ratios of the positive and negative electrodes, as well as the electrolyte, are based on values reported by Majeau-Bettez et al. (2011) in an LCA study on Li-ion batteries for electric vehicle batteries. Those values are used in Pillar 3 as a reference for battery ES systems due to the lack of information available for stationary applications. It is assumed that the production of LFP material is conducted by hydrothermal synthesis routed through the reaction of iron sulfate, phosphoric acid and lithium hydroxide. The main components and electrochemical characteristics of the modelled battery are provided in Table 3-1.

Table 3-1: Component Mass Breakdown and Performance of the Modelled Battery (LFP) (Majeau-Bettez, Hawkins and Stromman 2011)

Main Components	Li-ion Battery System (LFP) Details	Approximate Quantities (%)
Battery mass composition (%)	Positive electrode paste	24.8
	Negative electrode paste	8.0
	Separator	3.3
	Substrate, positive electrode	3.6
	Substrate, negative electrode	8.3
	Electrolyte	12.0
	Cell container, tab and terminals	20.0
	Module and battery packaging	17.0

[117] (Dubarry and Liaw 2009, Ellis, Lee and Nazar 2010, Kim, et al. 2013, Whittingham 2004)

	Battery management system (BMS)	3.0

3.2.3.2.2 Functional Unit

The functional unit measures the function of the studied system. A clearly defined and measurable functional unit needs to be consistent with the goal and scope of the study. The functional unit allows for making valid comparisons between products. It offers a reference to which the inputs and outputs of the product system are related. Provided that the main function of the product system is delivery of electrical power to the grid, the selected functional unit for this study was one MWh delivered by a large-scale battery pack.

3.2.3.2.3 System Boundary

According to ISO 14044, a system boundary of an LCA study is defined as a set of criteria specifying which unit processes are part of a product system[118]. For Li-ion, the system boundary of this LCA study contains the entire material production and manufacturing sequence (cradle-to-gate) of a Li-ion battery pack, operations phase, and recycling as the end of life scenario. For the use/operation phase emissions calculation, the methodology is explained in section 3.2.3.6.

In the field of LCA research, the simplification of life cycle inventories (LCIs) by applying cut-off rules without significantly affecting the overall results, is an integral part of every LCA study[119]. This includes excluding sub-components manufacturing and components recycling processes from the scope of a full LCA study, or using secondary data instead of primary data[120].

Due to the lack of consistent and reliable upstream manufacturing data and mass percentages of the sub-components materials of the battery cooling system and other balance of system (BOS) components for LFP batteries, the cradle-to-gate emissions for these processes were estimated based on values from literature. Additionally, this study modified data from generic sources and Ni-Co-Mg (NCM) battery recycling studies due to a lack of specific data for the recycling of LFP batteries.

As shown in Figure 3-3, a primary flow diagram represents the phases included in the system boundary of this LCA study. It is assumed that the geographical system boundary is the province of Alberta for all life cycle stages in order to exclude transportation to the project site. The current Alberta electric grid mix was assumed to provide energy requirements of life cycle stages.

[118] (ISO 2006b)
[119] (Valkama and Keskinen 2008)
[120] (Hur, et al. 2005)

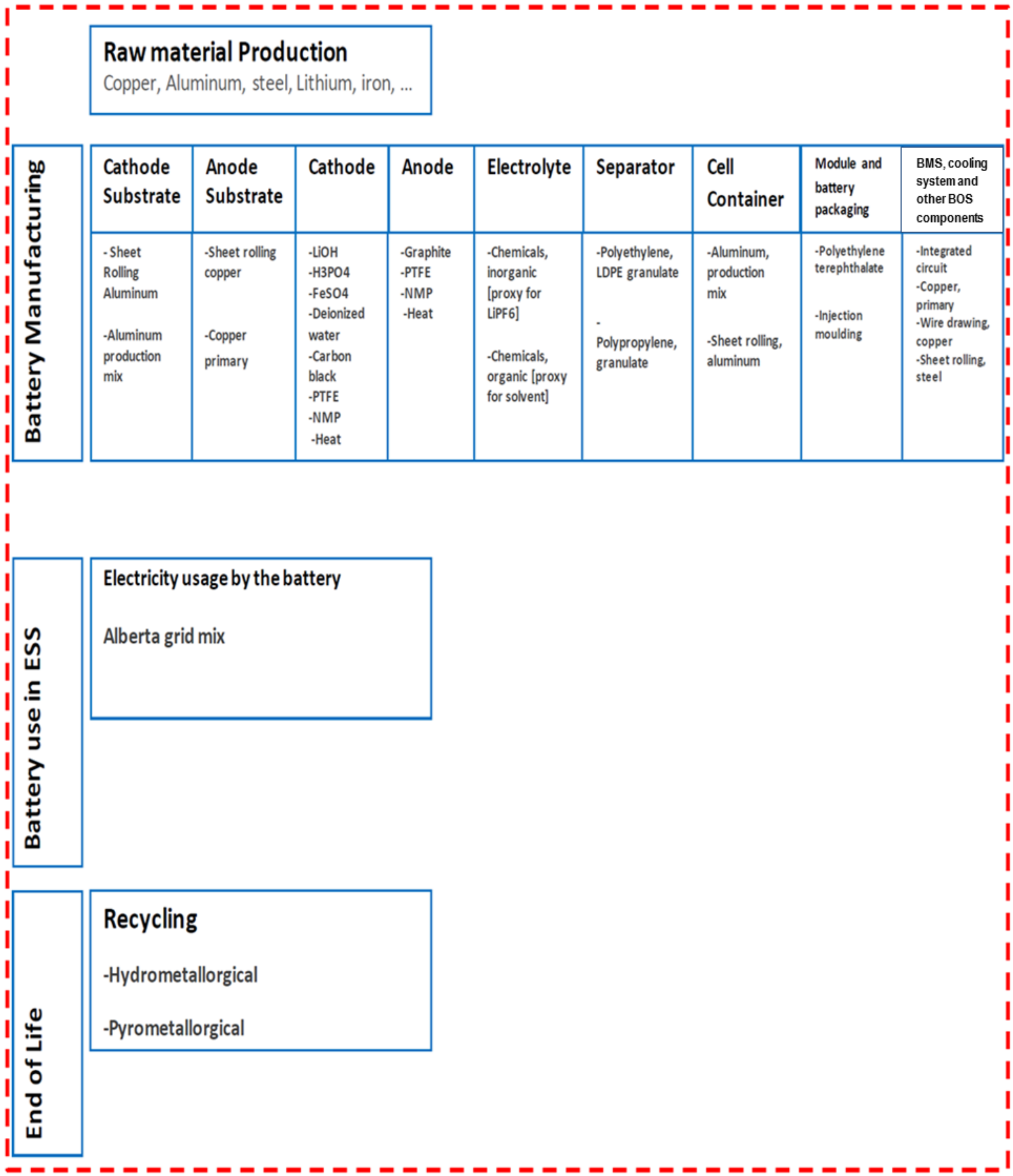


Figure 3-3: Flow-diagram of the System Function and Related Unit Processes

3.2.3.2.4 Impact Category and Impact Assessment Method

The results of the inventory analysis are assessed in the impact assessment phase, in which selection of impact categories has significant implications on the results. The selected method to weigh and model the results is classification and characterization following the Dutch method ReCiPe 08 Midpoint (H) which is employed in the

SimaPro LCA software tool[121]. ReCiPe Midpoint (H) version 1.12 includes 18 impact categories given the availability of LCI data[122].

Based on the data sources used in this LCA study and their related limitations, as well as scope of this LCA study, only a global warming potential (GWP) indicator (kg CO2 eq.) is represented in the final environmental LCIA category results. The selected impact category covers the main issues relevant to Li-ion batteries ES and CAES systems related to air, water and energy resources.

3.2.3.2.5 Process Flowchart and Initial Data Requirements

Figure 3-3 provides some details on unit processes related to the Li-ion battery ES systems. Four main steps are defined in the system boundary including raw material production, battery manufacturing, battery use, and end of life including recycling. The Life Cycle Inventory data is required for all the cradle-to-gate processes. However, the battery operations phase and recycling phase are included in Figure 3-3 to highlight the significance of the environmental performance of end of life operations. The operations phase emissions calculations are detailed in section 3.2.4.2. The data for recycling were obtained by extrapolating recycling process values of small laptop batteries from the Ecoinvent database, which is a database for several products used by SimaPro software to calculate environmental impact, and values on recycling of the NMC batteries reported by Simon and Weil (2013).

3.2.3.3 Life Cycle Inventory (LCI) Analysis

In order to model the inventory of a Li-ion battery pack life cycle during its life span, data was collected from previous studies[123]. Appendix XII shows a summary of the LCI for Li-ion battery packs. Note that a battery energy storage system also includes additional balance of system (BOS) components apart from BMS and cooling systems such as a power conversion system (inverter), transformer, and other auxiliary loads, which are not modelled in this LCI; however, their environmental impact $CO_{2\text{-eq}}$ emissions are estimated based on values from literature.

The manufacturing of LFP battery components was modelled using the primary LCI database from Majeau-Bettez et al. (2011) and Ecoinvent data sources. Majeau-Bettez et al. (2011)'s study provides the most updated and comprehensive inventory for LFP batteries[124], however the cooling system is excluded from their inventory. Peters et al. (2018) unified various LCIs for Li-ion batteries and implemented a common basis of comparison. It was found that assumptions related to cell manufacturing energy demand, electrode binder, and battery management systems (BMS) are key parameters that influence the results significantly; however, the cooling system was disregarded as a common component of the LCI studies.

The main components of a battery pack are the battery cell, module and packaging, BMS, and the cooling system (that is not modelled in this LCI). Main components of a battery cell are cathode, anode, electrolyte, separator, and cell container. The cathode and anode are merged at the battery assembly and a thin layer (200-

[121] (Goedkoop, et al. 2009)

[122] (Frischknecht, et al. 2007)

[123] (Ellingsen, et al. 2013, Hiremath, Derendorf and Vogt 2015, Majeau-Bettez, Hawkins and Stromman 2011, Notter, et al. 2010, Sullivan and Gaines 2012, Ziemann, et al. 2016)

[124] (Hawkins, Gausen and Stromman 2012, Hiremath, Derendorf and Vogt 2015)

250 µm for high energy cells) is then applied on both sides of the electrode substrates[125]. The cathode, the separator, and the anode are then inserted together and all are wrapped up in the cell container. The cells are then filled with electrolyte and the cell container is closed. A compliance test of cells in which the cells experience a determined number of charge/discharge cycles and are then mixed in modules and battery packs is the final step.

3.2.3.4 Major Assumptions and Limitations

A summary of major assumptions applied in this Li-ion ES battery LCA study is provided in Table 3-2. One of the main assumptions is about mass fraction for Li-ion battery packs based on the study by Majeau-Bettez et al. (2011). It is assumed that 17% of the battery mass is packaging, and 3% is for the battery management system (BMS).

According to Rydh and Sanden 2005[126], there is an uncertainty around the conceptual border between "manufacturing" and "material production," and it is believed that "material production" means being limited to pure metals, simple plastics, or raw chemicals. Additionally, it is assumed that the applied infrastructure onsite at the battery assembly plant has negligible material loss or emissions in the system. Note that the transportation of materials to the project site is not included in the assessment.

The Li-ion ES battery is assumed to have 85% round trip efficiency and a cycle life of 10,250 charging/discharging cycles (average value of total number of cycles to failure at 80% depth–of-discharge (DOD)). These battery technical characteristics assumptions are average values from literature review based on the techno-economic model of battery lifecycle costs study by Battke et al. (2013). Note that the ES round trip efficiency assumed in Pillar 1 is an average value for all the ES technologies categories modelled.

The number of battery stack replacements required during operation and maintenance of the battery pack required for a service life of 14 years was calculated using the calendrical life of the battery[127] and assumed to be an average value of 11.5 years for the calendrical life of Li-ion batteries[128]. Additionally, it was assumed that virgin materials were used for the production from cradle-to-gate[129]; however, all of the production materials for the battery stack replacements were from recycling materials, representing a closed-loop recycling process.[130]

Table 3-2: Major assumptions made for cradle-to-gate and recycling phases for Li-ion battery used in stationary application

Field of Assumption	Assumed
Battery type	Li-ion battery
Chemistry of applied Li-ion battery	LiFePO4/ Graphite
Battery capacity	1 MWh
Round trip efficiency	85%
Life time of ES system	15 years

[125] (Majeau-Bettez, Hawkins and Stromman 2011)

[126] (Rydh and Sandén 2005)

[127] (Hiremath, Derendorf and Vogt 2015)

[128] (Battke, et al. 2013)

[129] (Majeau-Bettez, Hawkins and Stromman 2011)

[130] (Denholm and Kulcinski 2003)

Battery cycle life (total number of cycles in battery life time)	10,250
Contribution of the battery mass	Table 5 in Majeau-Bettez et al. (2011)
Transportation of all phases	Omitted
Infrastructure at the battery assembly plant	All assumed to be negligible in comparison to other stages.
Battery lifetime	Assumed to be a period of 15 years in the stationary applications
Electricity generation	Alberta grid mix according to Alberta Energy-2016: Coal (50%), natural gas (39%), hydro (2%), wind (5%), biomass (3%). Electricity generation for the re-manufacturing and re-use of the battery (battery stack replacement) as part of the recycling phase.

Most of the recent LCA studies on batteries focus on their application in the automotive industry, however there is a significant lack of specific LCI data for battery ES systems for stationary applications. Hence the life cycle inventory of an electric vehicle Li-ion battery pack and the BMS components are scaled up to the energy resources and materials required for upstream processes to support and manufacture a large scale Li-ion battery pack to be used as a component of an ES system. Figure 3-4 shows a schematic setup of a utility-scale Li-ion battery energy storage system (BESS) and indicates the system components that are included in the primary Li-ion LCA system boundary such as the battery pack, the BMS components, the battery thermal management (cooling system), and the other BOS components like the power conversion system-PCS (inverters) and transformers.

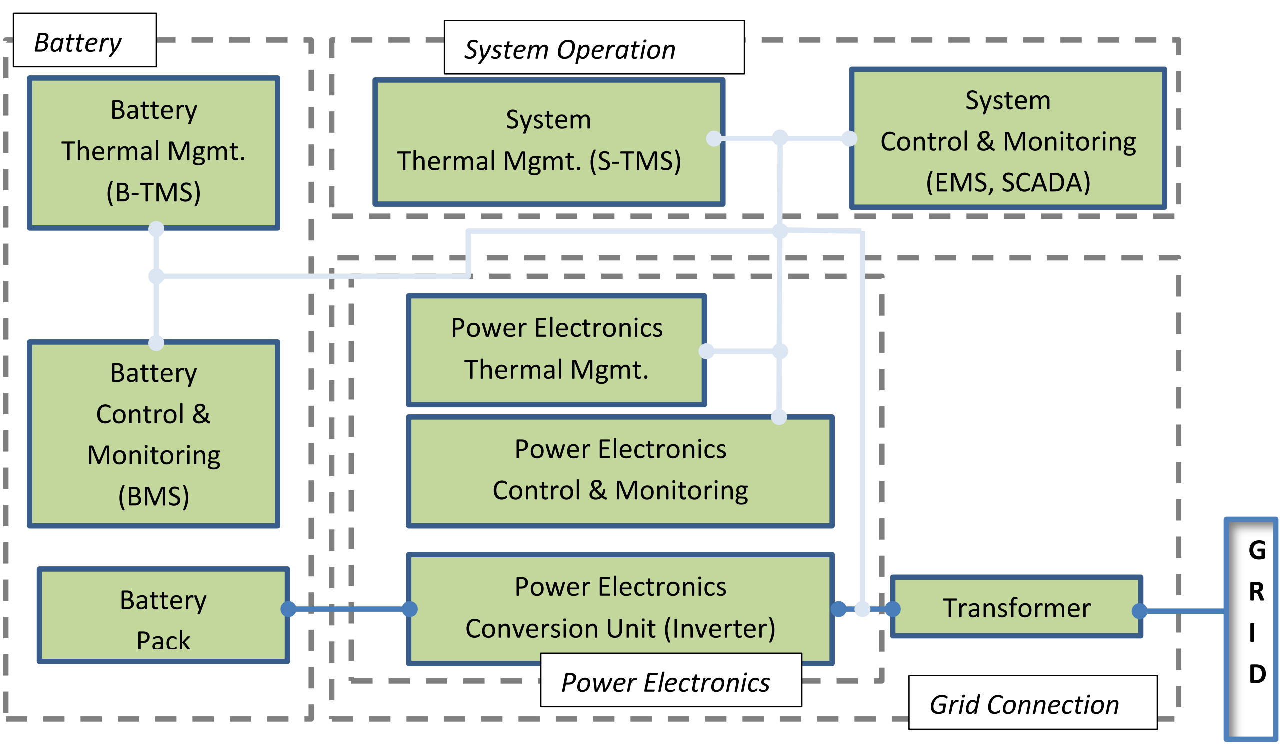


Figure 3-4: Utility-scale Battery Energy Storage System Topology adapted from (Holger, et al. 2017)

For clarity in the figure above, light blue lines indicate auxiliary power supply; blue lines indicate main energy storage power flow.

Although the cooling system and other BOS components such as the inverters and transformer were not modelled in the cradle-to-gate life cycle inventory, qualitative assumptions were made to estimate the cradle-to-gate CO_2 emissions of these components based on previous studies related to the GHG emissions associated with grid connection components in utility-scale BESS. In the case of the cooling system, it is assumed that the contribution of a cooling system to the total cradle-to-gate GHG emissions of a battery pack is approximately 2% based on the results of an LCA study of NCM type batteries by (Ellingsen, et al. 2013).

In regards to other BOS components, Table 3-3 provides the share of each BESS component on total cradle-to-gate emissions for three types of BESS obtained from literature. The GHG contribution of the BOS components, transformer and inverter, for each BESS are in the range of 32% to 47%. For this LCA study, it is assumed that the CO_2 emissions generated by the manufacturing of the transformer and inverter have an average contribution of 40% of total cradle-to-gate GHG emissions of a utility scale Li-ion battery ES system.

Table 3-3 : Share of BESS Components on Cradle-to-Gate GHG Emissions (%)

Battery Type	PSB (Sodium-Polysulphide-Regenesys) - 15 MW/120 MWh [131]	VRB (Vanadium Redox Flow Battery) - 15 MW/120MWh [131]	Li-ion – 5 MW/5 MWh [132]
Battery pack materials and manufacturing	59% [133]	68%[133]	53%[134]
PCS (inverter)	15%	11%	30%
Other BOS (transformer and other electronics)	27%	21%	17%[135]

3.2.3.5 CAES Systems

The LCA of compressed air energy storage (CAES) systems is performed by following the same steps as in Li-ion battery ES systems. Hence, it is not discussed in detail here. The principle of CAES is the utilization of the elastic potential energy of compressed air. Energy is stored by compressing air in an air-tight underground storage cavern. To utilize the stored energy, compressed air is drained from the storage vessel, heated and then expanded through a high pressure (HP) turbine, which captures some of the energy in the compressed air. The air is then combined with fuel and combusted, with the exhaust expanded through a low pressure (LP) gas turbine[131]. The CAES system in this LCA study is comprised of air compressors and associated cooling equipment,

[131] (Denholm and Kulcinski, Life Cycle Energy Requirements and Greenhouse Gas Emissions from Large Scale Energy Storage Systems 2004)

[132] Koj et al. (n.d.)

[133] Includes electrolyte and power stack

[134] Includes battery rack (46%), BMS (3%), and thermal mgmt. system (4%)

[135] Includes transformer (13%) and cables, switchgear (4%)

combustion turbine expanders, inlet air heat recuperators, natural gas combustion chambers, AC electric generators, and transmission components.

The main function of this product system is to deliver electricity to the electric grid. Consequently, it is assumed that the system boundary will include the usage of natural gas that is burned to operate the gas turbine.

The system boundary of this CAES LCA study contains the entire material production and manufacturing processes of the CAES system, operations phase, and recycling as the end of life scenario. For the use/operation phase emissions calculation, the methodology is explained in section 3.2.3.6. There is a lack of specific data for recycling, therefore the CAES LCA study utilized modified data from generic sources and qualitative assumptions based on other ES technologies LCA studies such as batteries. The LCI includes all major processes and significant materials, and energy flows to the point where materials are extracted or emitted to the natural environment. Figure 3-5 shows a primary flow diagram representing the components included in the system boundary of the CAES system.

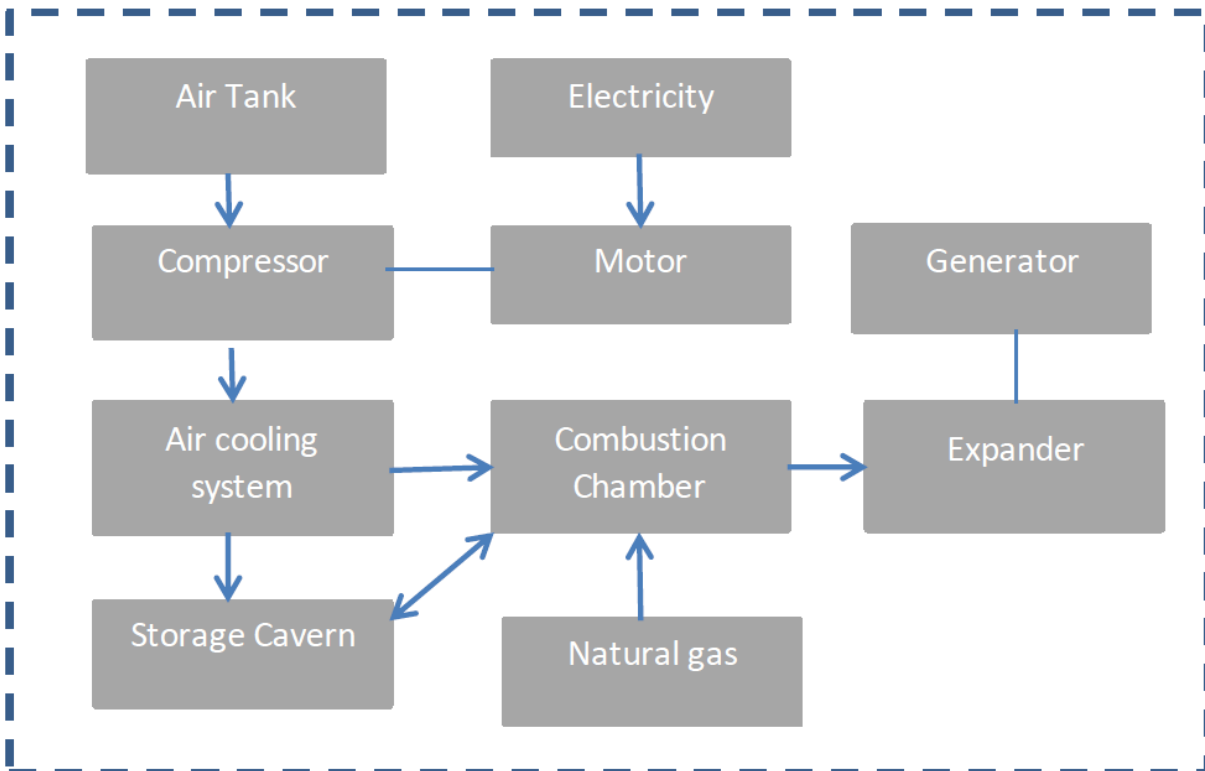


Figure 3-5: Schematic Diagram of Gas Turbine Generation and Compressed Air Energy Storage System

The main assumptions for CAES systems are given in Table 3-4. Due to the lack of reliable data related to materials and energy requirements for construction of the buildings and other infrastructures onsite at the CAES plant, it has been excluded from the assessment. It is assumed that GHG emissions from plant construction are negligible in comparison to others CAES system components. Further, the transportation of materials to the project site are not included in the assessment. Note that transportation of natural gas is included.

Table 3-4: CAES LCA Main Assumptions

Field of Assumption	Assumed	Reference

Geographic boundary	Province of Alberta, Canada	
Type of CAES system	Conventional CAES using natural gas turbine	
Life time	25 years	(Oliveira, et al. 2015)
Capacity factor	20%	(Denholm and Kulcinski, Life Cycle Energy Requirements and Greenhouse Gas Emissions from Large Scale Energy Storage Systems 2004)
System efficiency	74%	(Denholm and Kulcinski, Life Cycle Energy Requirements and Greenhouse Gas Emissions from Large Scale Energy Storage Systems 2004)

To model the life cycle inventory of a CAES system during its life span, data were collected from previous studies[136]. The manufacturing of components was modelled using Denholm et al. (2004), Oliveira et al. (2015) and the generic data sources of Ecoinvent. Regarding the life cycle inventory analysis, electricity used in the manufacturing of the CAES product was modelled considering the Alberta electricity grid mix in 2016. Appendix XII provides a summary of the LCI for CAES system.

As mentioned above, given that the technology is relatively new, and end of life scenarios have not been studied heavily, in general there is a lack of data regarding end of life options for compressed air systems such as recyclability or impact on waste streams. However, according to existing studies on recycling, and by applying recycled primary materials such as steel instead of virgin materials to produce a new CAES system, this study has attempted to qualitatively consider the significance of the recycling process. It is assumed that some materials return to the cycle, therefore their impacts are assessed and applied as credits to the recovery of the materials in the end of life.

3.2.3.6 Operations Phase

As mentioned previously, the grid-level GHG emissions resulting from the usage of ES systems are evaluated considering changes on the grid electricity generation sources over time as a result of ES integration. The following methods were utilized to calculate operations phase emissions at the system level and for technology comparisons.

3.2.3.6.1 System Level GHG Emissions Based on Changes to Fossil Fuel Consumption

The production cost analysis described in section 1.3.1.2 performs grid simulations for case studies with no storage in the grid and with installed storage in the grid from 2017 to 2030. The annual consumption of fossil fuels (i.e. coal and natural gas) was calculated for each case and the difference (ΔGHG) was calculated according to Eq.1.

$$\Delta GHG = (-) \sum_{i=1}^{n} (F_{NS,i} - F_{WS,i}) \times EI_{F,i} \qquad (1)$$

[136] (Denholm and Kulcinski, Life Cycle Energy Requirements and Greenhouse Gas Emissions from Large Scale Energy Storage Systems 2004, Chen, et al. 2009, Lund and Salgi 2009, Oliveira, et al. 2015)

Where $F_{NS,i}$ is the consumption of fuel type i for no storage case, $F_{WS,i}$ is the consumption of fuel type i with storage case and $EI_{F,i}$ is the emission intensity of fuel type i (obtained from a national inventory report) (Canada 2016).

As the case studies include the capacity additions of wind, solar and natural gas generation as well as coal retirements, the fuel consumption values reflect the prospective changes in the Alberta electricity grid which include the effect of increasing levels of ES integration. Hence, the ΔGHG values indicate the net emissions from grid over the period of study as a result of differentials of fuel consumption during the benchmark scenario and the ES capacity scenario with complete charging/discharging cycles.

Overall, the ES environmental impact on the Alberta electric grid is calculated considering the total GHG emissions from manufacturing (cradle-to-gate) of ES technologies in addition to the grid level GHG emission reductions from usage of ES technologies based on changes in fossil fuel consumption. In the case of CAES systems deployment, GHG emissions from natural gas usage on CAES systems operation take into account their overall environmental impact calculation. It is assumed that GHG emissions of 229 gCO_2/kWh from the stack are due to natural gas combustion on CAES systems (Huang , et al. 2017).

3.2.3.6.2 GHG Emissions Based on Grid Emission Factors for Technology Comparisons

The functional unit of an LCA plays an important role in relation to comparability. When performing LCA of energy systems, the functioning of the power plant under assessment needs to be taken into consideration in the LCA; to be comparable within the same functional unit, individual technologies should provide the same service to the system (Turconi, Boldrin and Astrup 2013).

For this LCA case study, the functional unit of the cradle-to-gate and recycling LCA model used for both types of ES systems evaluated in this LCA section is related to the energy delivered to the grid based on average values of their complete utilization over their cycle lives or lifetime and expressed in MWh. Pillar 3 therefore performs the comparative cradle-to-gate impact assessment of both ES technologies assuming that the energy discharged to the grid is delivered during their respective complete lifetime utilizations, regardless of the type of service provided to the grid. Then these 'cradle-to-gate' emission values are normalized to a service lifetime of 14 years. This is the basis of comparison with the report's overall period of study in order to get direct cradle-to-gate impact comparisons between these ES technologies.

The operations phase impact for each ES technology is considered a function of the quantity and type of energy consumed and dispatched during overall ES operation. Therefore, the operations phase impact for each ES technology under this technology comparison approach only considers the electric grid losses from the overall usage of each ES technology. The charging and discharging emissions are annual average values estimated by using grid marginal emission factors and round trip efficiencies of the specific technologies.

Emission factors, which describe the GHG emissions associated with the generation of a unit of electricity (e.g. $kgCO_2e/MWh$), can be used to evaluate the emissions from ES systems considering different ES technologies during their usage in the grid. There are two types of emission factors, namely average and marginal emission factors. The average emission factor (AEF), which is called the grid average (GA) by Alberta Environment and Parks, is the average amount of GHG emissions associated with the generation of a unit of electricity. It is calculated by dividing total emissions from the grid by total electricity generation. The marginal emission factor (MEF), which is called the operating margin (OM) by Alberta Environmental and Parks, is evaluated as the increase of emissions for a change in electricity demand that will be met by the generators that are operating on the margin (Yang 2013). Unlike AEFs that provide a grid average emission intensity value, the MEFs measure the impacts on incremental change on the grid. They have been used to understand the impact of having an additional demand on top of the existing demand, in cases such as electric vehicles (Ma, et al. 2012) and displacement of existing generation by renewable sources (Thomson, Harrison and Chick 2017).

In this study, both AEFs and MEFs were calculated using the annual generation mix values from 2017 to 2030 derived from the production cost simulation in Pillar 1. The AEF was calculated according to Eq.2.

$$\boldsymbol{AEF = \frac{\sum_{i=1}^{n} E_i \times EI_i}{\sum_{i=1}^{n} E_i}} \qquad \textit{(2)}$$

Where E_i is the generation per year per fuel type i and EI_i is the emission intensity of the generation by fuel type i.

The MEFs were calculated according to Eq. 3 by selecting the fuel types operating on margin and assuming the same generation mix as the annual generation mix as proposed by Farhat et al. (2010).

$$\boldsymbol{MEF = \frac{\sum_{i=1}^{n} E_{M,i} \times EI_i}{\sum_{i=1}^{n} E_{M,i}}} \qquad \textit{(3)}$$

Where $E_{M,i}$ is the generation per year per marginal fuel type i and EI_i is the emission intensity of the generation by fuel type i on the margin.

For the MEFs calculation of the Alberta electric grid using equation 3, the following parameters were identified. First, coal generation, all types of natural gas generation, and hydropower are qualitatively assumed as marginal fuel sources based on the length of time these resources provide power on the margin during on-peak and off-peak hours of grid operation. In a previous study, Farhat et al. (2010) showed that the Alberta winter peaking load is supplied mainly by natural gas and coal power plants, while the remaining is supplied by hydro resources. Likewise, Doluweera, et al. (2011) calculated the MEFs of the Alberta electric grid assuming that the marginal generation units are the price setting generators based on the percentage of time that each generation technology sets as the system price in Alberta’s whole sale electricity market. Figure 3-6 displays how frequently each generation of technology sets the system marginal price. Over each of the last five years, coal generation was the most common marginal price-setting technology, typically at night rather than during the day. In 2017, coal generation set the system marginal price in more than half of the on-peak hours (AESO 2017b).

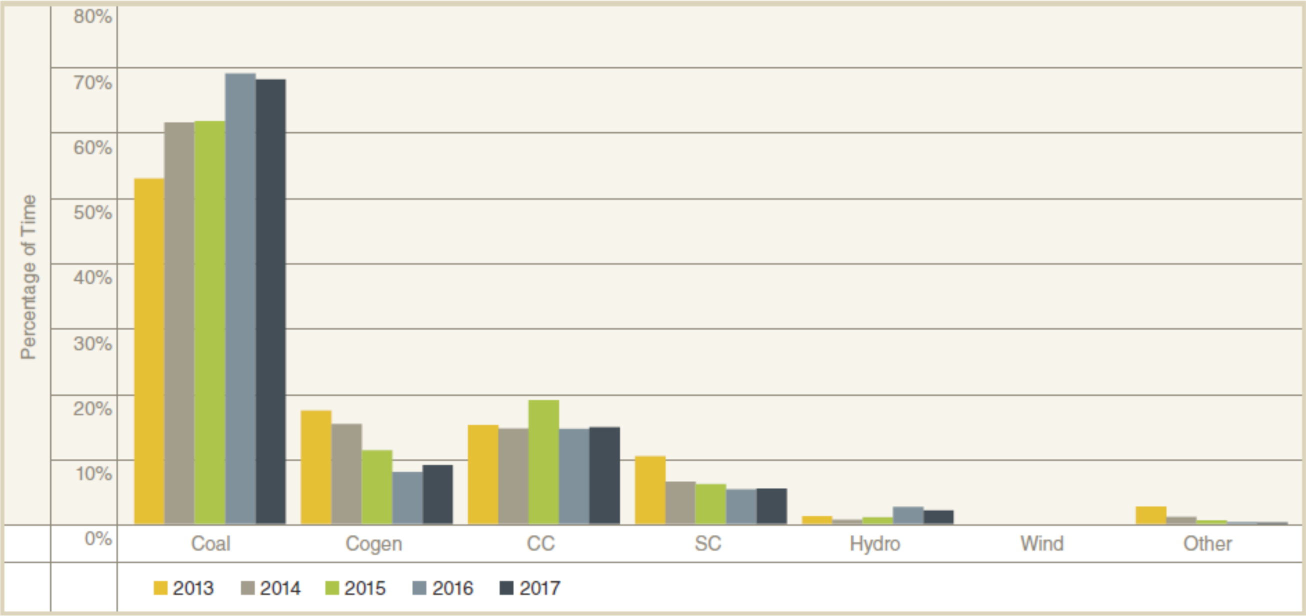


Figure 3-6: Annual Marginal Price-setting Technology (AESO 2017b)

Second, the emission intensity values used are the life cycle GHG emissions for each generation type as reported by various studies, as shown in Table 3-5[137].

The emission intensities of electricity generation technologies were aggregated as a result of literature reviews of a number of LCA studies from different electricity generation technologies. Each emission intensity value was calculated as the 50th percentile value in the dataset of lifecycle GHG emissions estimates for each generation technology.

In order to reflect the changes of Alberta's generation mix over time, the life cycle emissions' intensity values for four generation-facility types were considered: cogeneration, combined cycle gas turbine (CCGT), simple cycle gas turbine (SCGT), and coal-to-gas, which is assumed to be an SCGT with the highest emission intensity.

Doluweera, et al. (2011), using an economic allocation method, calculated a range of life cycle CO_2 emission intensity values for cogenerated electricity in Alberta. In Pillar 3, the highest emission intensity value of 410 kgCO_{2eq}/MWh was used. Similarly, based on a study done by O'Donoughue, et al. (2014), the CO_2 emission intensity values for CCGT and SCGT are life cycle GHG emissions values calculated for CCGT from 420 to 480 kg CO2-eq/MWh and from 570 to 750 g CO2-eq/kWh for SCGT. For the coal-to gas generation unit, the lifecycle CO_2 emission intensity was assumed as the maximum value in the harmonized lifecycle GHG emissions estimates data set for SCGTs. Both AEFs and MEFs were used in evaluating operations phase emissions of the ES technologies evaluated under the LCA perspective in this section.

Table 3-5: Emission Intensities of Generation Types

137 Doluweera, et al. 2011, Edenholfer, Pichs Madruga and Sokona 2011, O'Donoughue, et al. 2014, Turconi, Boldrin and Astrup 2013

Generation Type	Life Cycle Emission Intensity (kg CO_2e/MWh)
Coal [a]	1,050
Cogeneration [b]	410
CCGT [c]	450
SCGT [c]	670
Coal-to-gas[c]	860
Hydro [d]	4
Solar [d]	46
Wind [d]	12
Biomass [d]	18

(a) Turconi et al. (2013)
(b) Doluweera et al. (2011)
(c) O'Donoughue et al. (2014)
(d) Edenholfer et al. (2011)

The annual MEFs are calculated according to equation 3 by using the emission intensities in Table 3-5 and the quantity of power generation on the margin calculated based on the results of the Pillar 1 modelling. Regarding ES efficiencies, for battery ES systems, it is considered the round trip AC efficiency. It is important to note that the round trip AC efficiency indicator at the point of common coupling (PCC) for battery ES systems is calculated as a percentage value with the following equation:

Efficiency = energy output/energy input = (Ed-Ead)/Ec+Eac)*100

Where,

Ed: Delivered discharge energy (kWh)

Ec: Delivered charge energy (kWh)

Ead: Delivered auxiliary energy during discharge (kWh)

Eac: Delivered auxiliary energy during charge (kWh)

Note: Auxiliary energy represents the electric energy delivered to satisfy auxiliary loads not accounted for at the PCC meter. An auxiliary load may include, but is not limited to, controls, cooling systems, fans, pumps, and heaters necessary to operate and protect the system (ESIC 2016).

For the Li-ion battery energy storage system, an AC round trip efficiency of 85% is assumed, and for the CAES system an efficiency of 74% is assumed. With regard to the environmental impact during the CAES systems operation calculated for a charge/discharge cycle, GHG emissions of 229 gCO_2/kWh from the stack due to external natural gas combustion are also assumed (Huang , et al. 2017).

The MEFs calculated in this report represent the yearly average of marginal emissions.

3.2.3.6.3 Other Methods of Evaluating Project Level GHG Emissions of ES Usage

The concept of emission baselines is described in standard protocols that were developed for implementation of the Kyoto Protocol under the Clean Development Mechanism (CDM). Baselines are used to quantify the amount of GHG emissions in the hypothetical 'what would happen otherwise' case against which actual monitored project emissions are compared (OECD 2002). Protocols have been used to quantify the avoided emissions by renewable energy projects compared to the baseline ('Otherwise') scenario. These scenarios are defined using different emission factors, namely operating margin (OM), build margin (BM) and combined margin (CM). This methodology is used consistently for renewable energy in all emission offset registries and transactions.

OM quantifies the GHG avoided by modification of the operation of existing plants. The methods used to calculate OM are the same as the AEF and MEF calculations described above; hence, OM is identical to AEF or MEF. Often, MEFs are used as OM. BM defines the effect of the current project in avoiding the future plants that would have been otherwise built. It is calculated as the emission intensity of the otherwise built plants. The Grid Displacement Factor (GDF) is a weighted average of the OM and BM and results in a single parameter to provide the effect of current grid operation and future developments.

Solas Energy Consulting (2017) used ISO-14064-2 methodology and specifically integrated the OM and BM approach to estimate the GHG impacts from energy storage in Alberta. They estimated hourly OM using 2015 generation data and generated custom Grid Displacement Factors for a number of energy storage services and technologies based on the GDF when charging and discharging. A project level GHG analysis was then performed based on each ES technology and each service provided.

3.2.4 Evaluation of Environmental Impact of Energy Storage Systems

Overall GHG emissions from the Alberta electric grid as a result of ES systems deployment during the period of study are calculated by adding overall cradle-to-gate GHG emissions of ES, i.e. GHG emissions from manufacturing of ES systems, and aggregated grid-level GHG emissions (reductions/increments) from ES operation in the grid.

A life cycle impact comparative assessment for two ES technologies (Li-ion and CAES) is also presented in this section. More granularity and sensitivities can be added when LCA results of more ES technologies become available.

3.2.4.1 Manufacturing (Cradle-to-Gate) and Recycling Phase Emissions of ES Technologies

GHG emissions of Li-ion battery and CAES systems from their respective cradle-to-gate and recycling stages were calculated according to the LCA methodology in section 3.2.3 by using the SimaPro LCA software 8.3 Developer version to model the cradle-to-gate and recycling processes for each ES technology. Table 3-6 shows the GHG emission intensity results for Li-ion and CAES systems manufacturing and recycling life cycle phases.

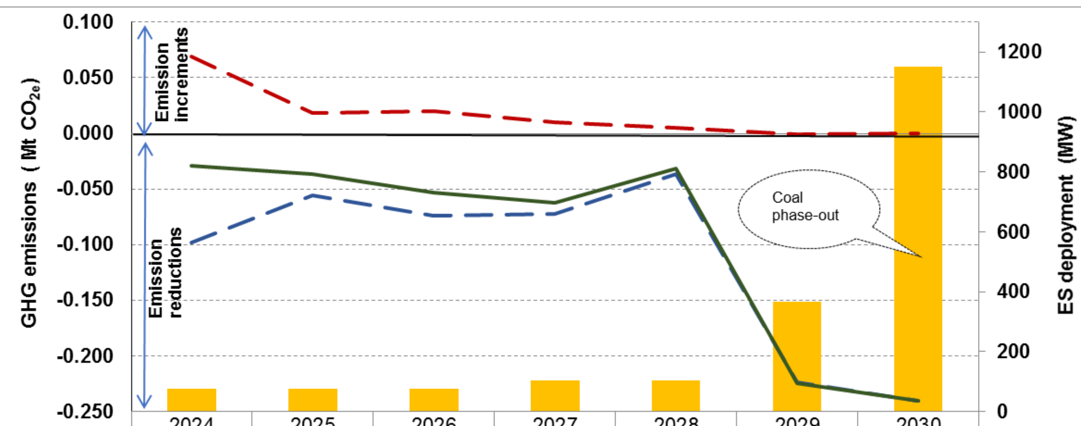
The manufacturing (cradle-to-gate) and recycling GHG emissions are relative values expressed in $kgCO_{2e}$ per MWh delivered to the grid considering an average complete lifetime utilization for each ES technology. Note that CAES systems can deliver larger amounts of energy to the grid than Li-ion systems. For the Li-ion ES battery system, the cradle-to-gate impact comprises the GHG emissions from the manufacturing of three components: the battery pack, thermal management system, and BOS components (transformer and inverter). ES operations phase emissions for the Li-ion battery and CAES systems are calculated in the following section.

Table 3-6: GHG emissions during manufacturing and recycling for Li-ion and CAES Systems

GHG emissions ($kgCO_{2e}/Mwh_{delivered}$)	Li-Ion	CAES
Manufacturing (cradle-to-gate)	**243**	**65**
Battery pack	141	
Thermal management system (estimated)	5	
BOS (estimated)	97	
Recycling	**-19**	**-19**

3.2.4.2 ES Operations Phase Impact at Grid Level

The fossil fuel CO_2 emissions reductions as a result of ES operation in the Alberta electric grid for the benchmark scenario are calculated by taking the difference of fossil fuel yearly consumptions for the benchmark compared to ES Capacity scenario according to Eq.1 in section 3.2.3.6.1. The net grid-level GHG emissions reductions from ES usage are shown in Figure 3-7 expressed in negative values. The accumulated GHG emission increments (positive values) from coal consumption over the period of study represent a total value of 0.12 Mt of CO_{2e}. This emissions increment presents a yearly gradual reduction and reflects the low level of coal consumption used for ES charging (as the lowest cost energy source) before coal phase-out from the grid in 2030. Meanwhile, accumulated GHG emission reductions from natural gas consumption show a total emissions reduction of 0.8 Mt of CO_{2e} due to the increasing displacement of natural gas powered units when ES discharges to the grid from 2024 to 2030. Consequently, the aggregated fossil fuel GHG emission reductions are 0.68 Mt of CO_{2e} as a result of ES operation in the Alberta electric grid from 2017 to 2030.



	2024	2025	2026	2027	2028	2029	2030
ES deployment (acumulative)	75	75	75	103	103	367	1152
Coal	0.069	0.018	0.020	0.010	0.005	-0.001	0.000
Natural gas	-0.098	-0.055	-0.074	-0.073	-0.037	-0.224	-0.241
Net GHG emissions	-0.029	-0.037	-0.054	-0.062	-0.032	-0.225	-0.241

Figure 3-7: Net Fossil Fuel GHG Emission Reductions due to Energy Storage Operation in the Alberta Electric Grid (2024-2030)

Given there are fuel consumption differentials during charging/discharging of ES technologies 1, for the Alberta electricity system there is a slight increase in coal consumption during ES charging before coal is removed from the grid in 2030, and an increasing reduction of natural gas consumption as a result of displacement of natural gas powered units by ES usage when coal is phased out from the grid. As a result of these fuel consumption differentials, the net GHG emissions reductions from ES usage at the grid level are expected to be negligible by 2030 for the Alberta electricity system. *Therefore, there is not a significant difference between Alberta electric grid-level GHG emissions with and without ES over the period of study.*

3.2.4.3 Overall GHG Emissions of Energy Storage at Grid Level

Given that cradle-to-gate life cycle impact results from Table 3-6 are only for individual Li-ion and CAES systems, they were aggregated, re-scaled, and considered as a whole ES system to calculate total cradle-to-gate life cycle emissions at grid level for the AIES over the benchmark simulation period, and expressed in absolute terms ($MTCO_{2\text{-eq}}$). Pillar 3 assumes that the value of the cradle-to-gate life cycle emissions of an aggregated ES system of 1,152MW, which is the total ES deployment in the Alberta electricity system according to the ES Capacity scenario, is calculated by extrapolating the cradle-to-gate LCA results for individual systems (Li-ion and CAES). It is also assumed that ES deployment begins in 2024 (although at minimal levels initially) according to the Pillar 1 simulation results in section 1.5. Taking into account the distribution of ES within the four storage categories used in Pillar 1, the ES capacity result suggests that Li-ion storage may be deployed during all the suggested deployment years and CAES may be only deployed in 2030.

With regard to the annual capacity (MW) to be deployed for each ES technology (Li-ion battery and CAES) from 2024 to 2030, Pillar 3 assumed eight allocation scenarios of Li-ion and CAES systems for the total ES deployment in 2024, 2027, 2029, and 2030. The annual capacity distribution among Li-ion battery and CAES systems per scenario is estimated by applying assumed allocation factors for each technology to the annual ES deployment for the ES Capacity scenario. Details are shown in Appendix XIII.

Figure 3-8 shows the ES GHG emissions at the grid level for different ES deployment scenarios, expressed in $MTCO_{2\text{-eq.}}$Each environmental impact scenario is obtained by adding the overall ES cradle-to-gate emissions estimated for each scenario and the grid-level GHG emissions reductions from ES usage over the period of the study of the ES capacity scenario. The cradle-to-gate emissions from ES systems for each ES deployment scenario are discussed in detail in Appendix 15.

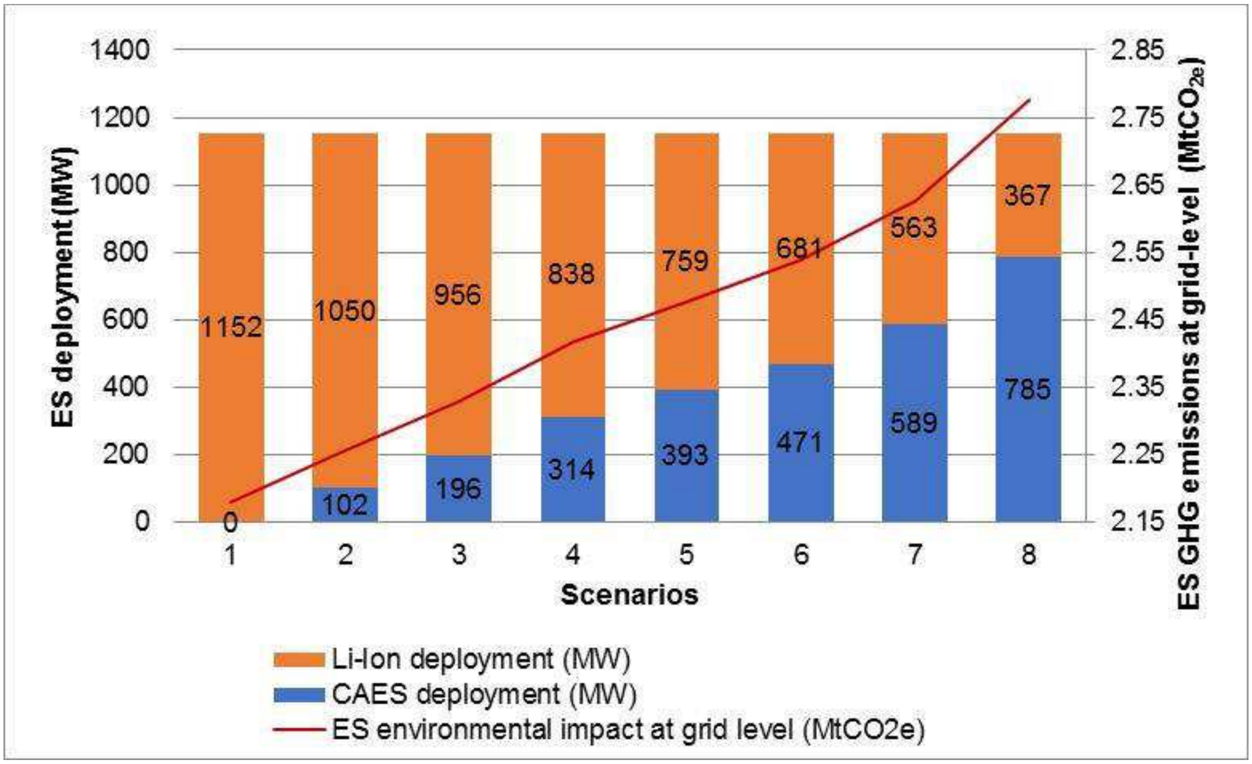


Figure 3-8: ES Environmental Impact at Grid Level for Different ES Deployment Scenarios

Scenario 1 indicates that the lowest quantity of GHG emissions from ES systems deployment is generated if only Li-ion battery ES systems are deployed by 2030, while scenario 8 shows that the highest ES environmental negative impact expressed in GHG emissions is produced if 75% of the total ES systems deployment corresponds to CAES deployment by 2030, since GHG emissions from CAES manufacturing are higher than Li-ion batteries if these are expressed in $MTCO_{2\text{-eq}}$/MW deployed, see Appendix 19. For scenario 7, the total ES system's deployment by 2030 is equally distributed among Li-ion battery and CAES systems. Note that overall GHG emissions from ES systems manufacturing (cradle-to-gate) surpass grid-level GHG emissions reductions from ES usage in all the assumed ES systems deployment scenarios.

As was pointed out in section 3.2.4.2, the comparison between GHG emissions generated from the benchmark scenario without ES and ES capacity scenario in the Alberta electric grid presents no major differences over the period of study. Figure 3-9 shows that grid-level GHG emissions with ES usage decrease by 46% from 2017 to 2030, primarily due to fuel substitution of natural gas for coal and additions of wind capacity. If the annual cradle-to-grate GHG emissions of ES systems is included, this overall GHG emissions reduction only drops to 42%. Therefore, GHG emissions from ES manufacturing (cradle-to-gate) generate an impact of 4% increment on the overall GHG emissions in the Alberta electric grid with ES over the period of study, and the majority is in a single year, 2030, with the deployment of large scale CAES. Note that annual GHG emissions values from ES manufacturing (cradle-to-gate) in Figure 3-9 correspond to scenario 7 in which the proportion of Li-ion to CAES systems is equal.

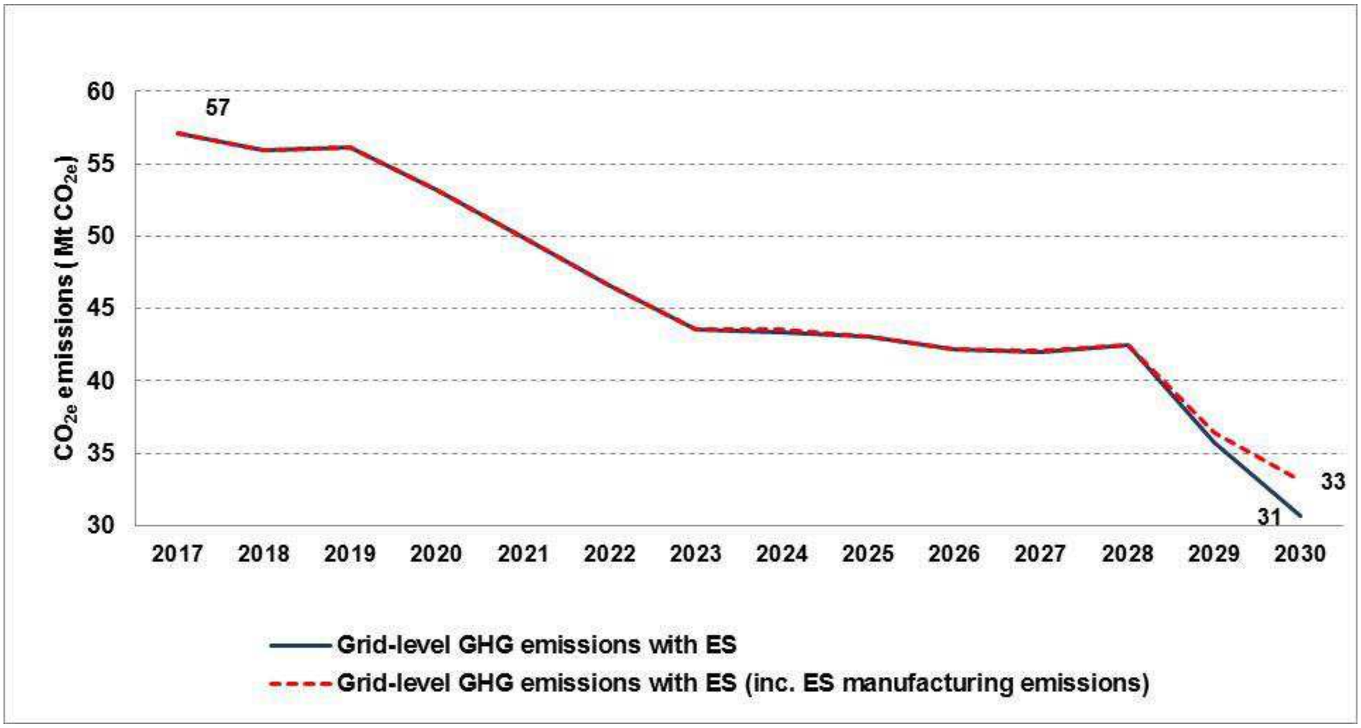


Figure 3-9: Annual Grid-level GHG Emissions with ES in the Alberta Electric Grid (2017-2030)

3.2.4.4 Technology Comparisons

In order to compare the life cycle impact of Li-ion battery and CAES systems in terms of emission intensity, i.e. amount of total GHG emissions per MWh delivered to the Alberta electric grid, the cradle-to-gate and recycling impacts of these two ES technologies in Table 3-6 are normalized to a 14-year service life time, which is assumed as a basis of a life cycle impact comparison. The operations phase emission intensity for this comparative life cycle impact assessment of ES technologies is calculated below.

3.2.4.4.1 Operations Phase Emissions for ES Technology Comparison

The operations phase emissions are calculated using grid marginal emission factors and round trip efficiencies of each ES technology.

Overall, the marginal and average emission factors for Alberta’s grid electricity system are calculated according to Eq.1 and Eq.2 in section 3.2.3.6.2 using the energy generated by fuel type over the study period modelled by Pillar 1 in section 1.5 and the emission intensities of generation types. Figure 3-10 shows that both emission factors present a reduction over the period of study of 37% and 51% respectively. These reductions on emissions factors are driven by changes in fuel mix in the AIES as the transition from coal to natural gas.

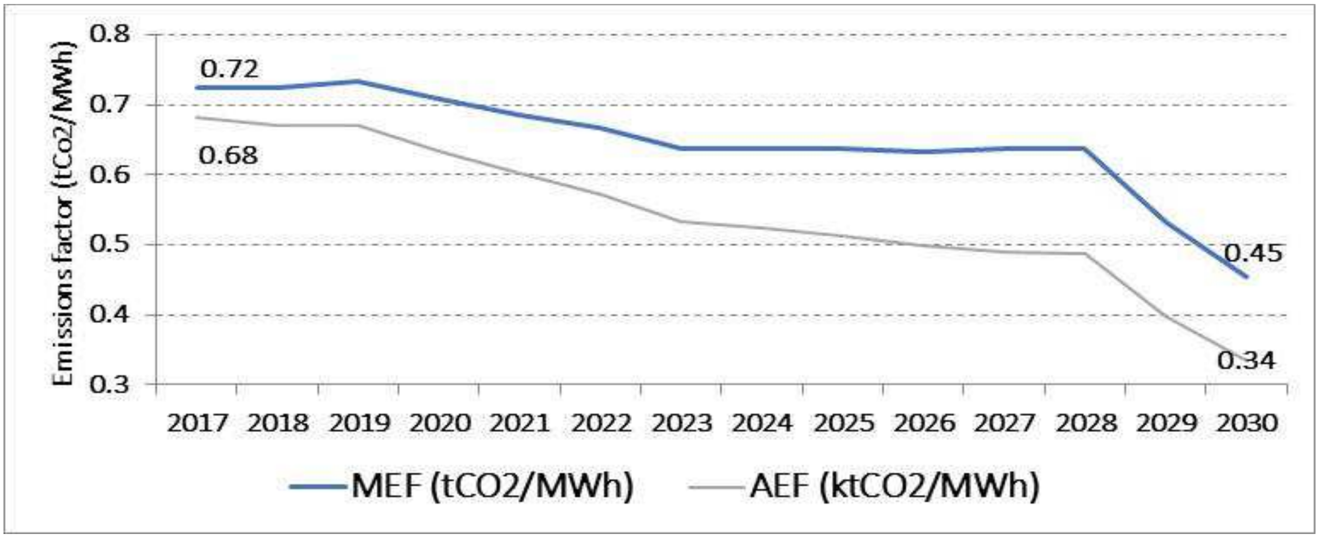


Figure 3-10: Marginal Emission and Average Emission Factors, ES capacity scenario

(*) MEF= marginal emission factor; AEF= average emission factor

Due to the evaluation of the operations phase GHG emissions at different Alberta power-grid mix scenarios over the period of study, an ES deployment is assumed for each year during this period. Table 3-7 shows the operations phase GHG emissions per specific ES technology which are considered as average grid electricity losses from ES use and calculated as the differential of charge/discharge cycle emissions per MWh delivered to the electric grid. The charging and discharging emissions are annual average values estimated by using the respective annual MEF and the round trip efficiency of the specific technology. The ES operations phase emissions for Li-ion batteries decrease from 109 to 68 kg CO2-eq/MWh in 2017 and 2030 respectively; similarly CAES systems' operation phase emissions drop from 417 to 347 kg $CO_{2\text{-}eq}$/MWh in 2017 and 2030 respectively. Note that the annual CAES systems' operation phase emissions also include the GHG emissions of 229 kg $CO_{2\text{-}eq}$/MWh from the stack due to natural gas combustion (Huang , et al. 2017).

Table 3-7: Operations Phase GHG Emissions for ES Technology Comparisons at Different Generation Mix Scenarios

ES use phase GHG impact (kg CO_{2e}/MWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Li-Ion	109	109	110	106	103	100	96	96	96	95	96	96	80	68
CAES	417	417	420	413	407	402	395	395	395	394	395	395	367	347

Further granularity with regards to GHG emissions reductions from different ES grid applications in Alberta is evaluated in the Solas Energy Consulting Report (2017).

3.2.4.4.2 Technology Comparisons

A comparative life cycle GHG impact analysis for Li-ion battery and CAES systems is performed at two different power–grid mix scenarios: 2017 and 2030 assuming ES deployment of these two technologies in 2017 and 2030. The cradle-to-grave (cradle-to-gate, operations phase, and recycling) impact of Li-ion battery and CAES systems is based on results presented in previous sections. Note that the Li-ion battery and CAES systems cradle-to-gate life cycle impact of 243 and 65 kg CO_{2e}/$MWh_{delivered}$ respectively, which are based on their complete lifetime utilization over their respective cycle lives or lifetime assumed in Table 3-2 and Table 3-4, are normalized to a

14-year service lifetime, i.e. assumed in this LCA study, and re-scale to 296 and 116 kg CO_{2e}/MWh delivered respectively in order to make direct comparisons between technologies. The life cycle GHG impact of each ES technology is shown in Figure 3-11, where Li-ion has less cradle-to-grave emissions than CAES systems in both generation–mix scenarios. Although CAES manufacturing is less emission intensive than Li-ion based on the results from Table 3-6, in regards to cradle-to-grave emissions, Li-ion is less emission intensive than CAES when taking into account the charging/discharging emissions which are determined by the round trip efficiency of each technology.

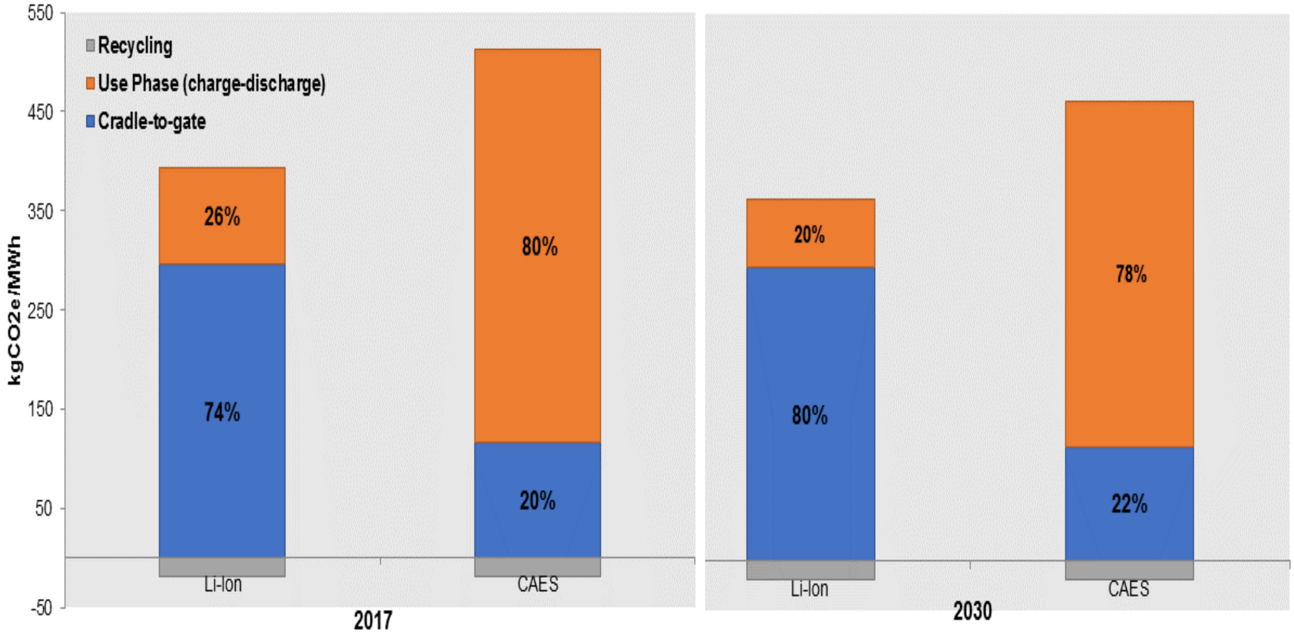


Figure 3-11: Life Cycle GHG Impact Comparison for ES Technologies

According to Hiremath et al. (2015) round-trip efficiency and power-grid mix are key input parameters to evaluate the effect on life cycle impacts of batteries from variations of these parameters. Figure 3-12 shows the relationship between the changes of the life cycle GHG impact of each ES technology and the changes of the GHG emissions of the power-grid mix. The gradient of the lines indicates the inverse of the round trip efficiency values of the ES technologies, which means the higher the efficiency, the lower the slope, and thus the lower the increase of the life cycle GHG emissions of ES technologies with increasing emissions by the power-grid mix. The relative position of CAES varies substantially as the GHG emissions from the grid generation sources start increasing over time, and its life cycle impacts increasing at a much higher rate than those for Li-ion.

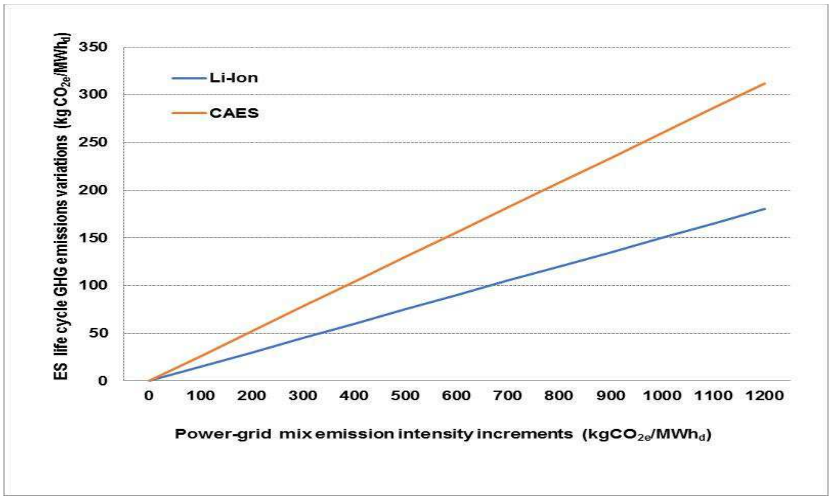


Figure 3-12: Dependency of the Changes of the Operations Phase GHG Emissions from ES Technologies on the Variations of the GHG Emissions from Grid Generation Sources. Adapted from (Hiremath, Derendorf and Vogt 2015)

3.2.4.5 Life Cycle GHG Emission Intensity for ES Technologies

Table 3-8 shows the life cycle GHG emission intensity values expressed in GHG emissions per electricity delivered to the Alberta electric grid ($kgCO_{2e}/MWh_d$) for the two ES technology types analyzed in this section, Li-ion batteries and CAES, based on the cradle-to-gate, operations phase and recycling LCA results presented above. Note that cradle-to-gate life cycle GHG emissions are evaluated on a per technology basis considering their respective complete life time utilization periods assumed in this study. The operations phase life cycle GHG emission values correspond to the ES operations phase GHG emissions by 2030 when the highest level of ES deployment is achieved over the period of study according to the ES capacity scenario from Pillar 1.

Table 3-8 will be updated over time when LCA results of more ES technologies become available.

Table 3-8: Life Cycle GHG Emission Intensities of ES Technology Types

ES Technology Type	Life Cycle GHG Emission Intensity (kg CO_{2e}/MWh)
Li-ion battery	292
CAES	393

3.3 Socio-Economic Impact Assessment

In Pillar 3, input-output economic models (IOM) were used to evaluate the economic impact of ES deployment in Alberta. IOMs track the changes of industrial outputs in the supply chain according to a shock (change) in the final demand of a given industry. The increase in the final output of a particular industry increases the demand on industries that supply goods and services, creating ripple effects throughout the economy. These effects are measured by input-output multipliers, which are estimated using the coefficients of IOM. Statistics Canada collects national and provincial data and creates and maintains national and provincial accounts and IOMs for Canada. Industries are combined into 233 aggregates at the most detailed level of the Canadian input-output tables available.

3.3.1 Methodology for Economic Impact Assessment of ES Projects

The bill-of-goods approach is most appropriate when analyzing a new industry or an industry without a lot of granular data. This approach relies on an accurate description for the first round of purchases for a particular industry (BEA 2013). In the context of this socio-economic impact study, this involves the accounting of direct purchases by the ES industry from other industry categories. It requires identifying the front-end goods and services requirements of the project supply chain and quantifying the incremental spending on those goods and services. Once relevant supply chain industries are determined, the provincially-bought goods and services are identified. The calculated expenditure values are assigned to appropriate input-output model categories. This overall methodology of evaluating socio-economic values is shown in Figure 3-13.

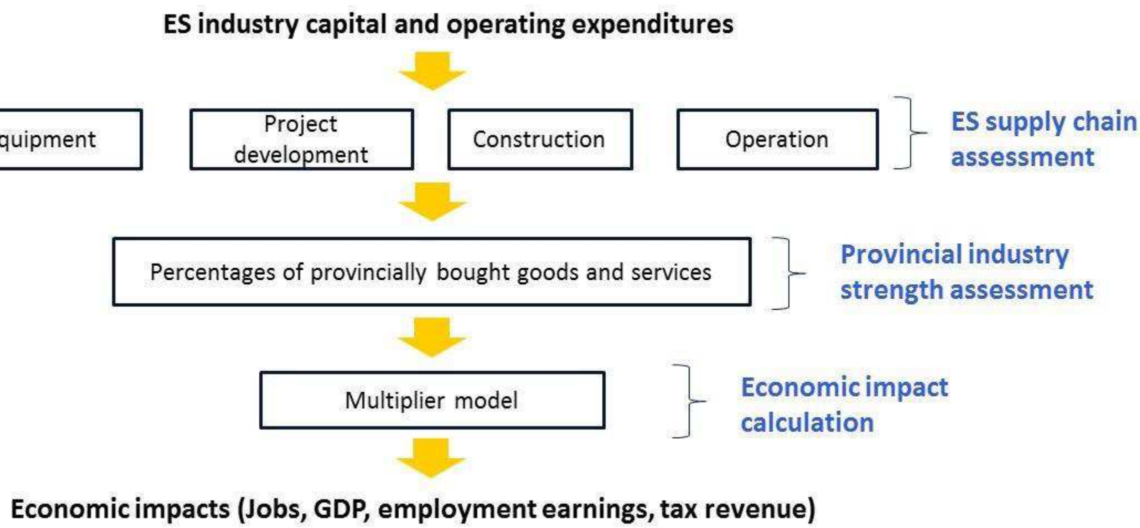


Figure 3-13: Methodology of Estimating Socio-economic Impact

Once the capital and operating expenditures are assigned to relevant industry categories, those increases in the demand can be entered into the IOM. The following types of impacts can be calculated using IOMs.

Direct Impacts – Result from expenditures associated with construction and operation of the project (1st round of spending), e.g. compensation for employees, taxes paid, capital formation, and profits.

Indirect Impacts – Involve the 2nd round of spending, which is the economic benefits of industries in the supply chain, hiring more workers and improving capacities to increase their output. Direct + indirect impacts represent the minimum value of economic impacts.

Induced Impacts - Result from the increased employment earnings of the workers in the project and supply chain industries causing more spending in the economy. Direct + Indirect + Induced impacts represent the maximum value of economic impacts. This is because workers may choose to spend their earnings outside the considered region (e.g. another province or country).

The socio-economic impacts can be evaluated using the following indicators:

- GDP
- Number of jobs
- Employment earnings

- Tax revenue

The main assumptions of socio-economic impact assessment are shown in Table 3-9 below.

Table 3-9: Main Assumptions of Socio-Economic Impact Assessment

Field of Assumption	Assumed Value or Input
Jurisdiction boundary for economic expenditures	Alberta
Economic structure	Current Alberta economic structure as given by Input-Output tables was assumed to be valid for project horizon
Spending of the economic benefits (employment income)	All the spending occurs inside Alberta
ES supply chain inputs	- Electrical power engineering construction - Electrical power transmission and distribution - Electrical equipment manufacturing - Battery and related devices manufacturing - Consulting and financial services - Government services

3.3.2 Socio-Economic Impact of Deploying ES in Alberta

According to the Pembina Institute (2016), there is an employment potential in the clean energy sector in Alberta, and investing in grid modernization projects like ES would create sustainable employment growth for those engaged in related equipment installations.

Figure 3-14 shows the potential economic impact of ES projects in terms of the number of jobs created during planning and development and construction stages in the Province of Alberta. The number of jobs are calculated based on the average capital cost of the ES technology deployed during the period of study, taking into account the decreasing cost of ES technology over time. As can be seen, most local jobs are created (direct impact) during the construction phase of ES projects, i.e. 1,553 jobs are created during the construction phase as opposed to 501 jobs created during the project planning and development stage. Regarding the total impact, including induced jobs, the number of jobs created during the project planning and development, construction, and operation stages is 859, 2,872, and 47 respectively.

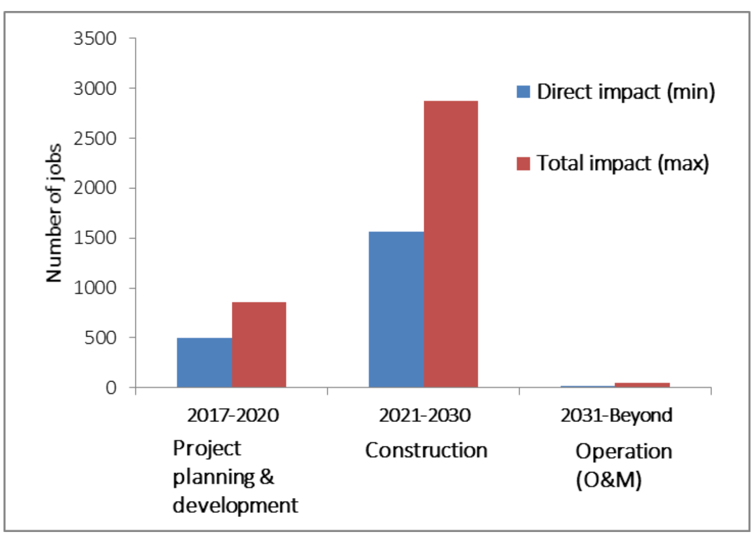


Figure 3-14: Socio Economic Impact of Deploying Energy Storage Systems in the Province of Alberta

Table 3-10 shows a comparison of the reported direct impact of renewable energy and ES projects during the construction and operation stages in Alberta. The direct impact of ES projects is estimated using a job factor that is expressed as the total number of jobs created per total MW installed during each project stage.

Table 3-10: Direct Impact Comparison to Renewable Technologies

Project Type	Jobs/MW (Direct Impact)	
	Construction	Operation (O&M)
Wind	0.95*	0.1*
Solar	12.5*	0.3*
Energy Storage	**1.76**	**0.2**

(*) Jeyakumar (2016)

3.4 Conclusions: Environmental and Socio-Economic Impact

Overall, in this environmental and socio-economic impact assessment, two environmental and socio-economic impact indicators were identified to analyze the sustainability aspect of ES deployment in the Alberta electric grid, including GHG emissions and number of jobs created. The analyses of these impact indicators were completed using the environmental life cycle approach and the input-output economic model (IOM) method respectively. Based on these analyses, several important results of the overall environmental and socio-economic impact relative to the prospective deployment of ES systems in the Alberta electric grid from 2017 to 2030 were obtained.

Overall, at the grid level, the GHG emission calculation, which is evaluated for 1,152MW of ES deployment (as determined by the analysis in Pillar 1), considered two aspects: GHG emissions reductions due to the operation of ES, which is based on changes in fossil fuel consumption, and GHG emissions from ES implementation, which is calculated by extrapolating cradle-to-gate life cycle results for individual systems (Li-ion and CAES).

The resulting GHG impact of installing 1,152MW of ES leads to the following conclusions:

(i) Although there are some GHG emission reductions that are attributable to ES deployment, these do not surpass GHG emissions from ES systems manufacturing over the study period.

(ii) Large GHG emission reductions are less likely to happen; hence, energy storage cannot be justified solely from the GHG reduction perspective or by achieving GHG reduction targets.

(iii) Even the system level GHG emissions reductions from ES usage cannot alone justify developing ES infrastructure. The environmental impact from ES deployment, taking into account GHG emissions from ES manufacturing and operation in the grid, is insignificant in comparison to the overall anticipated GHG emissions reductions of the Alberta electricity system from 2017 to 2030. The grid-level GHG emissions without ES decrease by 45% while system level GHG emissions with ES decrease by 42%.

- An LCA approach was used to perform a comparative life cycle GHG impact analysis of Li-ion battery ES and CAES systems to the Alberta electricity system at two power-grid mix scenarios, 2017 and 2030. The environmental performance of Li-ion batteries indicates that this ES technology generates 24% and 22%

less GHG emissions than CAES systems in 2017 and 2030 respectively. The cradle-to-grave LCA results indicate that the life cycle GHG impact of Li-ion battery ES systems are mostly affected by the emissions during manufacturing (cradle-to-gate stage) of the ES systems components, specifically the battery pack. In the case of CAES systems, they produce significantly higher emissions during the operations phase, originating from natural gas combustion during system operation, exacerbated by low CAES system round-trip efficiency.

- The life cycle GHG impact of Li-ion battery ES and CAES systems indicates that the overall contribution of the use stage to the overall life cycle impact depends upon the round-trip efficiency and the changes on the power-grid mix. Round trip efficiency is considered to be the major ES parameter that affects the life cycle impact results and consequently the ES ranking with regards to the environmental impact to the grid.
- The methodology utilized for GHG emission calculations of ES operation is based on changes to fossil fuel consumption, where the system GHG emissions are based on results from Pillar 1. The GHG emission factor is initially calculated for each technology based on the use case assumptions. Independently, life cycle emissions for different technologies have also been calculated and compared.
- Life cycle emissions for CAES and Li-ion batteries are estimated based on the metric kg CO2e/MWh delivered to the grid. In order to compare these two technologies with different expected project life times, the LCAs for Li-ion battery and CAES were normalized to the energy generated during the 14-year study period. Initially, each cradle-to-gate is calculated for its expected project life time (Li-ion 15 years and CAES 25 years). The LCA metric used is $kgCO_2/MWh$ (delivered to the grid) not $kgCO_2/year$ (emitted per year), as is used by other studies (Solas Report). Note that LCA metric is based on the complete lifetime utilization for each technology defined in our LCA which describes the function of the ES system in delivering 1MWh to the grid. The latter is a necessary step to compare emissions between different technologies. It should be noted that the system boundary for the Li-ion battery storage to deliver 1MWh AC to the grid includes the inverter and transformer components. In the CAES system, transformers are included as well.

In regards to the socio-economic impact of ES deployment, it is evaluated through the number of jobs created by ES deployment in Alberta during ES projects' stages. Direct economic impacts are estimated and are based on local activities in the supply chain of the project; meanwhile, the total economic impacts include the indirect and induced activities outside Alberta. In more detail:

- The majority of economic impacts are generated during the construction phase in a similar way as in renewable energy projects. The economic impact is likely to be lower than, for example, in solar projects, as ES systems are usually modular and implemented with lower construction phase costs.
- Overall, direct jobs that would be generated in Alberta represent 55% of total jobs generated as a result of ES deployment, where planning and development, and construction and operations represent 24% and 76% of total direct jobs respectively.

Further study is recommended to perform a comparative analysis of life cycle GHG impacts on ES systems for different stationary grid applications, as the cradle-to-gate GHG impact would be affected by lifetime utilization of a specific application. Other studies have completed usage impacts by technology and services (Solas Report) but have not completed life cycle analysis. Similarly, the operations phase GHG impact is affected by the variations of the emission intensities in the power-grid mix when the ES system is charged and discharged according to a specific grid service. Furthermore, as in the Solas Report, hourly, monthly, or seasonal MEFs can be used to calculate operations phase GHG emissions for different ES grid applications using hourly generation data from simulation model and historical charge/discharge profiles.

4 Summary and Path Forward

ES for grid scale applications has gained significant attention in Canada's energy sector. There is an increased awareness that fundamental changes in the way we build, own, and operate our electricity systems are required. An integrated and cost-effective ES technology has the potential to deliver sustainable employment through new jobs, mostly related to ES construction and installation, and possible GHG reduction benefits to all Canadians while building the necessary steps for a sustainable electric infrastructure.

Initiated and led by the National Research Council Canada (NRC), this study provides analysis and results that can provide insights into the opportunities and challenges related to adopting ES technologies in Alberta up to 2030. It includes detailed cost-benefit analysis for grid scale ES from 2017 to 2030 that results in a projected capacity of 1152MW of ES by 2030 and estimates $155M CAD in net present benefits for electricity stakeholders in Alberta[138].

The study was performed under three key pillars that included estimating market opportunity, technology specific energy storage valuation and assessment, and economic and environmental impact. Across all three pillars, and in order to support the short-term deployment of storage technologies and long term sustainability of the grid-scale storage sector in Alberta, engagement of key stakeholders such as storage technology vendors, system integrators, regulators, power producers, and policy makers was critical.

- The market opportunity study took a technology-agnostic approach to evaluate the potential impact of ES on the AIES. Impact on the Alberta electric grid is assessed primarily through the pool price and other benefits such as generation cost savings and capital savings from avoided peaking plants. This study provided an optimistic review as future capacity market payments were considered in addition to energy market revenues consistent with energy-only market dynamics.
- In order to assess and communicate the value of ES systems, techno-economic analysis (TEA) was utilized to evaluate cost-effectiveness of ES use cases for different grid services in Alberta. Alberta stakeholders chose three ES technologies: Lithium ion (Li-ion); Compressed Air Energy Storage (CAES); and Pumped Hydro (P-Hydro).
- Life cycle assessment (LCA) was performed to evaluate the GHG emissions from ES cradle-to-gate processes and ES operation at grid level. The LCA study compared the environmental performance of Li-ion battery and CAES systems on the Alberta electricity system during complete life time utilization.

Other results of significance:

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[138] As stated in the Preface (pp. ii and iii), the policy changes that have taken effect since the analysis presented in this report was performed will likely have an impact on the results presented here. Specifically, the policy changes could lead to a decrease of up to 20% in the number of ES projects (all of which are long-duration applications) and a decrease in the NPV of ES projects (discussed in detail on p. iii).

- The costs of ES technology have significant impact on ES deployment. A 40% reduction in energy storage technology costs will yield a 60% increase in energy storage deployment. This study predicts a potential $155M net benefit from 1152MW of ES deployment in Alberta over the study horizon. The analysis also shows that electricity prices exhibit less volatility when ES systems are deployed in the bulk electric system even though a large amount of renewable generation is implemented.
- The economic impact is likely to be lower than in, for example, solar projects, as ES systems are usually modular and imported with lower construction phase costs. The construction phase however, is expected to create 2,853 jobs from 2021 to 2030.
- In the case of CAES systems, it is depicted that CAES has noticeably higher emissions during the operations phase. This amount of emissions originates from natural gas combustion during system operation, exacerbated by low CAES system round-trip cycle efficiency.

Path forward:

- Similar studies are being undertaken for other provinces in Canada.
- Regarding the Pillar 3 analysis, further study is recommended to perform a comparative analysis of GHG life cycle impact on ES systems for different stationary grid applications.

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6 Appendix I: Simulated Potential Energy Storage Facilities in the Benchmark and ES Capacity Scenarios

6.1 Potential Energy Storage Facilities

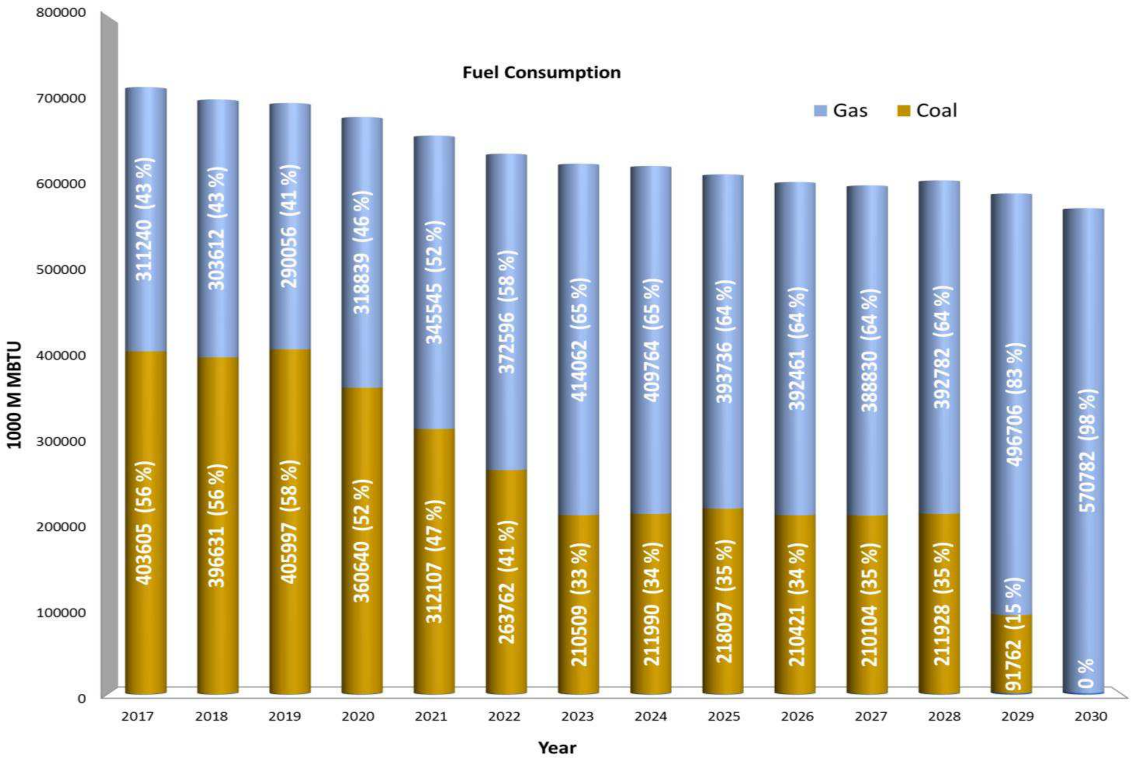
Energy Storage Location (Electric Node in PSSE)	Build Year	Long Duration (MW)	Medium-long Duration (MW)	Medium-short Duration (MW)	Short Duration (MW)
54040_N CALDE9	2024				3
54047_SHERWOO9	2024				3
54113_BLACKFA9	2024				3
54121_OLDS A9	2024				3
54242_HIGH RI9	2024				3
54252_CARSLAND	2024				3
54264_COWLEY 8	2024				3
54269_BURDETT9	2024				3
54271_BULLS H9	2024				3
54272_TABER A9	2024				3
54280_STIRLIN8	2024				3
54291_CONRAD 9	2024				3
54295_DRYCREEK	2024				3
54400_MONARCH9	2024				3
54519_CASTLTX2	2024				3
54555_ENMX14S9	2024				3
54566_ENMX20S9	2024				3
55121_CRYST L9	2024				3
55245_KINOSIS4	2024				3
55263_JOSLYN9	2024				3
55269_FIREBAGT	2024				3
55303_MAHIHKB9	2024				3
55576_ENMX47S8	2024				3
56546_EAST IN3	2024				3
57302_PRIM_25	2024				3
54150_WILLESD9	2027			4	
54320_CHAPPIC9	2027			2	
55126_FLYSHT/2	2027			6	
55276_S-SHINE3	2027			8	
55403_PAINTRT4	2027			9	
54020_EDSON A9	2029			9	
54059_REDWATE9	2029			9	
54107_SUNDREA9	2029			9	

54115_S RED DE	2029			9	
54150_WILLESD9	2029			5	
54220_HAYTER 9	2029			9	
54298_ALB NEWS	2029			9	
54320_CHAPPIC9	2029			7	
54398_BROOKFLD	2029			9	
54513_LAMBTON4	2029			9	
54545_EASTINT1	2029			9	
54559_ENMX13S9	2029			9	
54573_ENMX38S9	2029			9	
54592_ENMX41S9	2029			9	
54666_DOVER	2029			9	
54690_COALDAL9	2029			9	
55126_FLYSHT/2	2029			3	
55224_HANGSTO9	2029			9	
55226_WABASCA9	2029			9	
55230_AEC MILL	2029			9	
55276_S-SHINE3	2029			1	
55280_BRINTNEL	2029			9	
55285_NIPISI 7	2029			9	
55310_LEMING 9	2029			9	
54091_NISKU A9	2029		3		
54208_ENMX2S 7	2029		3		
54245_GLENWOO8	2029		3		
54260_JENNERE9	2029		3		
54278_WARNER 8	2029		3		
54336_SUMMER01	2029		3		
54343_TABERW1	2029		3		
54360_STONY P9	2029		3		
54383_JOFFRE 7	2029		3		
54405_CONKLIN3	2029		3		
54511_SUMMERS3	2029		3		
54512_DOME T29	2029		3		
54551_ENMX28S7	2029		3		
54561_ENMX11S7	2029		3		
54567_ENMX1SD9	2029		3		
54572_ENMX39S9	2029		3		
54586_ENMX30S9	2029		3		
54590_ENMX24S9	2029		3		
54780_SYLV_25B	2029		3		
55085_PEACE/29	2029		2		

55393_HILL 9	2029		3		
56219_BLACKMUD	2029		3		
56245_KINOSIS5	2029		3		
58692_N LETHB9	2029		3		
54579_ENMX31S9	2030		3		
55085_PEACE/29	2030		1		
54031_FINCAST9	2030	33			
54058_FORT SB9	2030	33			
54089_E EDMON9	2030	33			
54119_RD14S-B2	2030	33			
54234_CASTRIV1	2030	33			
54246_SPRING 8	2030	33			
54256_BROOKSA9	2030	33			
54270_SUFFIEL9	2030	33			
54348_LEISMER9	2030	33			
54369_CHRISLK2	2030	33			
54388_ELLIS2 9	2030	33			
54505_JASPER 4	2030	33			
54521_PETROLIA	2030	33			
54550_ENMX22SA	2030	33			
54568_ENMX5SG9	2030	33			
54574_ENMX37S9	2030	7			
54583_ENMX32S9	2030	33			
54588_ENMX8SE9	2030	33			
54589_ENMX26S9	2030	6			
54591_ENMX40S9	2030	33			
54680_MEDICIN7	2030	33			
54694_MAGRATH7	2030	33			
54699_RIVERBN9	2030	33			
55289_JACKPINE	2030	33			
55433_3HILLS/3	2030	33			

Table 6-1: Detailed Recommended Energy Storage Locations, Build Year, Category and Capacity in the Base Case

6.2 Fuel Consumption



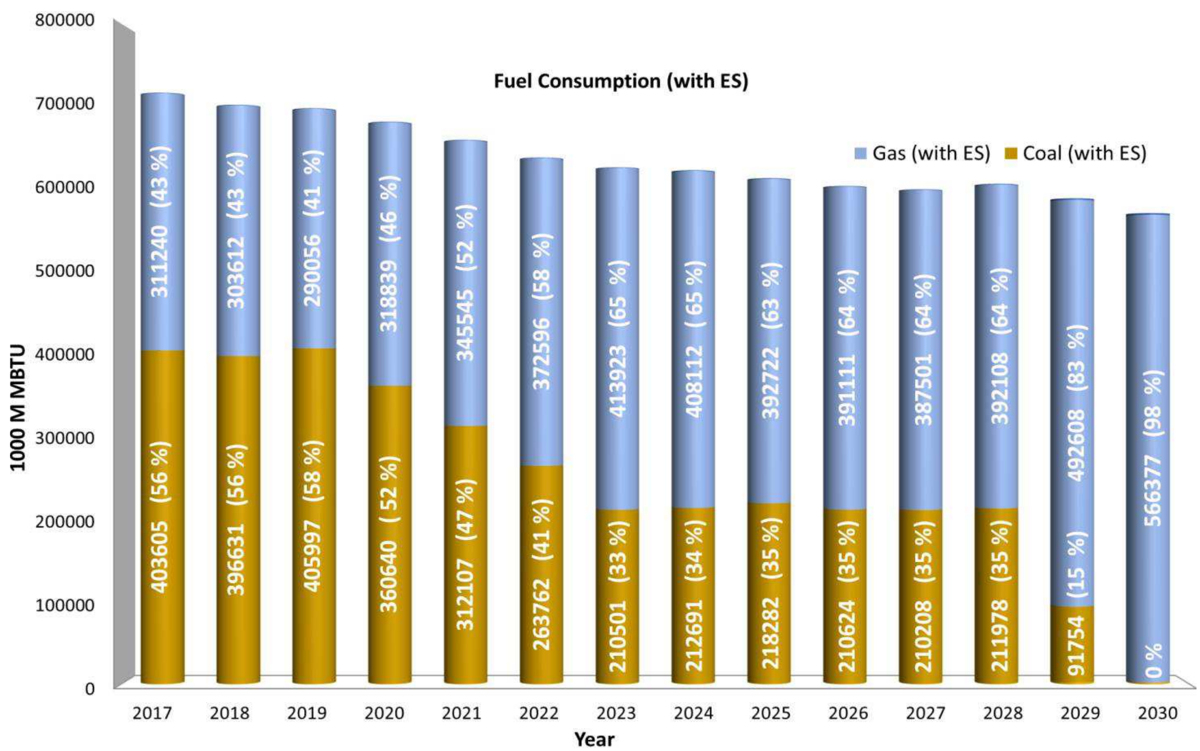
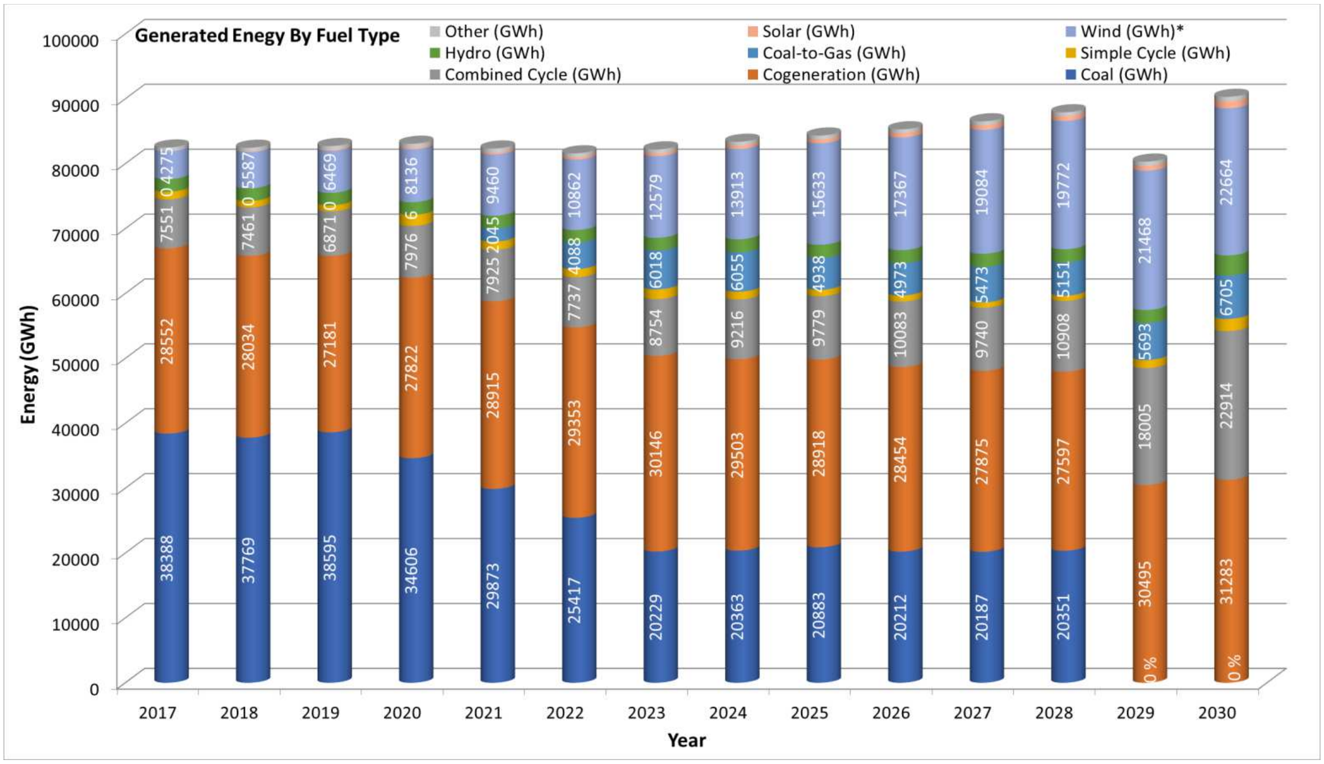


Figure 6-1: Fuel Consumption, MMBTU and Percentage of Total Fuels (Benchmark and ES Capacity Scenarios) over Study Period



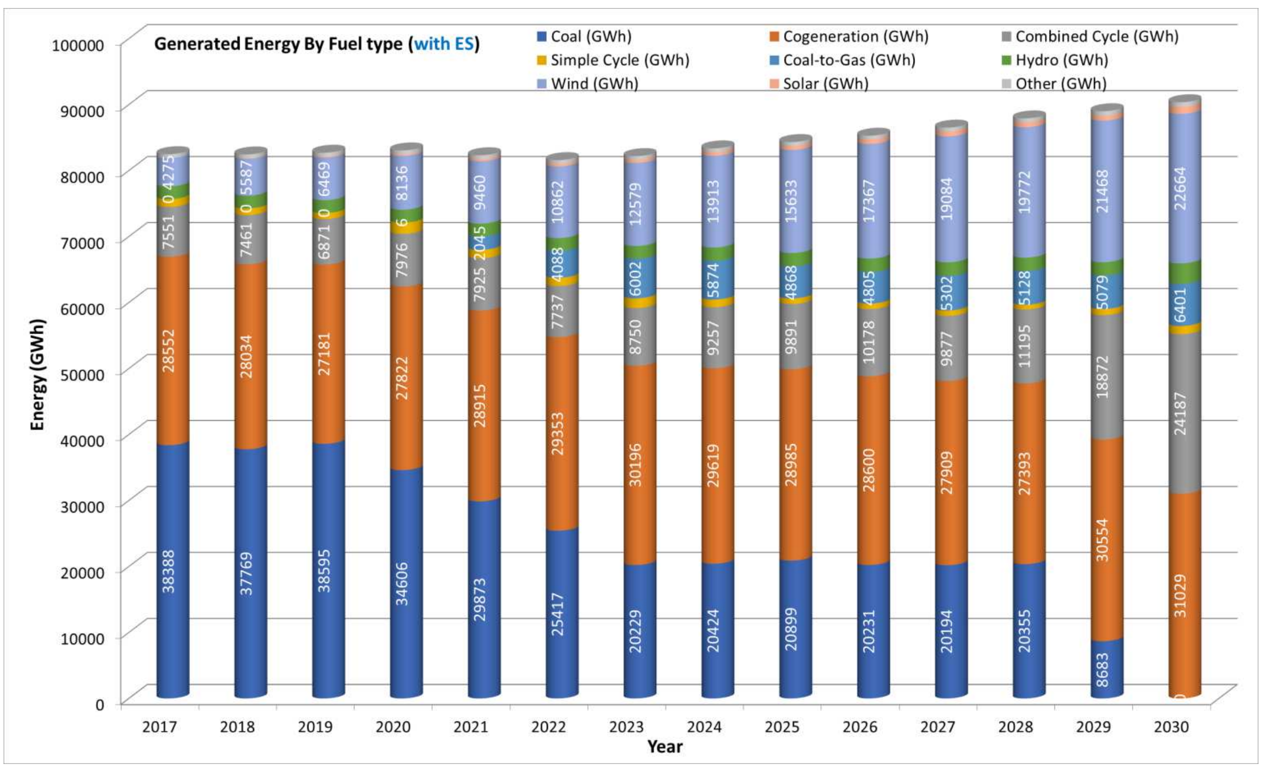


Figure 6-2: Generated Energy from Various Generation Assets by Fuel Type (Base Case with and without Energy Storage)

Additional Storage Benefit Assumptions	Value	Note

Frequency Response	$250,000/MW	50%
Black Start	$0.3/kW	
T&D Deferral	$3.4/kW	
Reactive Power Support	$2.19/kVar	0.75 pf
Peaking Plant Capital Cost1	$1200/kW	

Table 6-2: Benefit Calculation Assumptions

7 Appendix II: Wind and Solar Generation Stations Input to the Model

7.1 Wind Energy Generators

Generator Name	Location	Generator Name	Location
Ardenville W1	54166_PEIGAN 7	Summerview2	54336_SUMMER01
Blackspring Ridge_1	54400_MONARCH9	Taber Wind_1	54343_TABERW1
BlueTrail W1	54223_PINCHER8	Wild Steer Butte W1	54269_BURDETT9
CastlRk_W1	54223_PINCHER8	Wild Steer Butte W1	59662_SUBD1
CASTRIV2_1	54234_CASTRIV1	WildRose_W1	54685_MEDICIN9
CASTRIV3_2	54234_CASTRIV1	WildRose_W2	54685_MEDICIN9
ChinChuteW1	54389_HILLRIDG	Wintering Hills Wind_SC1	54260_JENNERE9
COWLEY N_1	54264_COWLEY 8	Yagos W1	58264_COWLEY N
Cowley Ridge W1	54271_BULLS H9	BluEarth Hand Hills Wind Project	54402_KETTLES1
FtMcleodW1	54271_BULLS H9	Capital Power Halkirk 2 Wind	55445_ROWLEY 9
Ghost Pine W1	54180_GHOST 9	Capital Power Whitla Wind Power	54269_BURDETT9
Halkirk 1 Wind	55469_BAT RV79	E.ON Grizzly Bear Wind	54831_MCBRIDET
HWY785 W1	54223_PINCHER8	Enel Alberta Riverview Wind Farm	54180_GHOST 9
Kettles Hill W1	54402_KETTLES1	Heritage Wind Energy Centre	54358_SODER1
Magrath Wind	54402_KETTLES1	Invenergy Schuler Windfarm	54336_SUMMER01
MCBRIDE2_1	57901_MCBRIDE2	Irma Wind Power	54296_GOOSEL7
MCBRIDE3_2	59901_MCBRIDE3	Joss MPC WAGF	54400_MONARCH9
MCBRIDE3_3	59901_MCBRIDE3	NaturEner Wild Rose 1 Wind Farm	54389_HILLRIDG
MCBRIDE4_4	58901_MCBRIDE4	NaturEner Wild Rose 2 Wind Farm	54320_CHAPPIC9
OldmnRvr_W1	54223_PINCHER8	Old Elm + Pothole Creek Wind Farm	54694_MAGRATH7
RiverView W1	54223_PINCHER8	Paintearth Wind Farm	55716_LAKESEN7
RpsCAwindAB1	54165_PEIGAN 4	RES Oyen Wind Power Project	54147_GAETZ 4
RpsCAwindAB1	54451_MATLB1	RESC Forty Mile WAGF	54343_TABERW1
SODER2	58358_SODER2	Wheatland WAGF Project	54284_BUTTE7
Soderglen1	54358_SODER1	Windy Point WAGF	54271_BULLS H9
Summerview1	54336_SUMMER01		

Table 7-1: Wind Generator Locations

7.2 Solar Energy Generators

Generator	Location
Solar1	54166_PEIGAN 7
Solar2	54166_PEIGAN 7

Solar3	54166_PEIGAN 7

Table 7-2: Solar Generator Locations

8 Appendix III: Energy Storage Systems Assumptions

8.1 Technology Capital Cost and Category

In order to keep Pillar 1 as technology agnostic as possible, Energy Storage capital cost and capacity assumptions for ES Technology Types were combined into four different categories which each include a bundle of potential technologies. The technology capital costs were based on previous studies[139], and only modified as necessary due to updates based on cited sources. A discount rate of 5% is applied here.

ES Technology			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Long (4+ hrs)	li ion, flow, thermal, emerging advanced chemistries, pumped hydro, CAES	per kW	1752.73	1579.96	1439.70	1325.99	1234.25	1160.96	1103.38	1059.47	1027.69	996.86	966.95
		per kWh	292.12	263.33	239.95	221.00	205.71	193.49	183.90	176.58	171.28	166.14	161.16
Medium long (2-4 hrs)	li ion, flow, vanadium redox batteries, sodium, zinc, VRLA	per kW	1237.22	1115.27	1016.26	935.99	871.24	819.50	778.86	747.86	725.43	703.66	682.55
		per kWh	309.31	278.82	254.06	234.00	217.81	204.87	194.71	186.97	181.36	175.92	170.64
Medium short (1-2 hrs)	li ion, VRLA	per kW	710.78	645.92	592.63	548.92	513.24	484.37	461.36	443.49	430.18	417.28	404.76
		per kWh	355.39	322.96	296.31	274.46	256.62	242.19	230.68	221.74	215.09	208.64	202.38
Short (half hour)	li ion, flywheels, ultracaps	per kW	390.93	355.25	325.95	301.91	282.28	266.40	253.75	243.92	236.60	229.50	222.62
		per kWh	781.85	710.51	651.89	603.81	564.57	532.81	507.50	487.84	473.20	459.00	445.23
Cost and cost decline sources: Lazard Levelized Cost of Storage 2017, GTM Research, Bloomberg, Navigant Research and industry input													
All costs are in 2017 US $ and reflect all in front of meter installation cost including land and interconnection.													

Table 8-1: Energy Storage Technology Capital Cost and Capacity by Category

8.2 Technical and Economic Life

It is further assumed that the economic life for all the energy storage is 10 years, and the technical life for the four categories of the energy storage technology is as in Table 8-2. Economic Life sets the number of years over which the Build Cost is spread. Technical Life is the physical life of the generator and is used in the capacity optimization phase to force the retirement of the generator after a certain period of time after it has been constructed.

Duration	Technical Life	Economic Life
Long	20	10
Medium Long	20	10
Medium Short	10	10
Short	10	10

Table 8-2: Energy Storage Technology Technical and Economic Life

139 "State of charge - Massachusetts Energy Storage Initiative" (page 83, undated), **http://www.mass.gov/eea/docs/doer/state-of-charge-report.pdf**

9 Appendix IV: Sample Simulation Model Input Data (Types)

Demand		
	Demand Profile	8760-hour Historical Demand Spreadsheet in MW
	Demand Profile	Sub-hourly Historical Demand Spreadsheet in MW
	Peak Forecast	Annual Peak Forecast Spreadsheet in GWh
	Energy Forecast	Annual Energy Forecast Spreadsheet in GWh
	Energy Efficiency	Annual Energy Efficiency Spreadsheet in GWh
	Demand Response	Annual Forecast of Peak Demand Reduction Spreadsheet in MW
Generation		
	BTM DER MW	Annual Forecast Spreadsheet in MW
	BTM DER Energy	Annual Forecast in Energy Spreadsheet in GWh
	Existing Generator (capacity, heat rate …)	Table with the existing generator's capacity, established year, …, unit type
	Generator Deactivations	Table with the proposed deactivated generator's capacity, deactivating year,…, unit type
	New Generator Additions	Table with the proposed new generator's capacity, activating year,…, unit type
	Solar Generator Profiles	Table with Solar Generator Gens' rating factor, capacity, etc.
	Wind Generator Profiles	Table with Wind Generator Gens' rating factor, capacity, etc.
	Hydro Generator Profiles	Table with Hydro Generator Gens' rating factor, capacity, etc.
Renewables Program		
	Wind Profiles	Spreadsheet with hourly historical energy
	Wind Profiles	Spreadsheet with sub-hourly historical energy
	Wind Capacity	Spreadsheet with annually historical of MW
	Wind Energy	Spreadsheet with annually historical of GWh
	Solar Profiles	Spreadsheet with hourly historical energy
	Solar Profiles	Spreadsheet with sub-hourly historical energy
	Solar Capacity	Spreadsheet with annually historical of MW
	Solar Energy	Spreadsheet with annually historical of GWh
	Hydro Profiles	Spreadsheet with monthly energy of the hydro
	Hydro Capacity	Spreadsheet with hourly historical MW
	Hydro Energy	Spreadsheet with monthly forecast of GWh
Emissions		
	CO_2 Emissions	CO_2 Emission Annually Forecast in tons
	CO_2 Price	Annually Auction Price / Tax Price
	NO_x Emissions	NO_x Emission Annually Forecast in tons
	NO_x Price	Annually Auction Price / Tax Price
	SO_2 Emission	SO_2 Emission Annually Forecast in tons
	SO_2 Price	Annually Auction Price / Tax Price
Fuel		

	Fuel Type Mapping	Spreadsheet of mapping specific fuel types supplied by specific hubs to generators
	Historical Fuel Price	One-year-back Fuel Price by Type (NG, Coal, Oil, DSM - Demand Side Management, Wood, ...)
	Fuel Prices Forecast	Daily/Weekly/Monthly Fuel Forecast by Type (NG, Coal, Oil, DSM - Demand Side Management, Wood ...)
Transmission		
	Transmission File	PSSE Model
	Interface Definition	Table of Interface Profiles
	Interface Constraints	Table of Interface Constraints
Imports		
	Imports MW	Spreadsheet with Hourly Historical Imports, in MW
Capacity Expansion		
	Storage Costs	Table with Storage Cost for different durations and technologies accordingly, spreadsheet with the annually cost forecast
	New Technology Costs	Table with Technology Cost for different durations and technologies accordingly, spreadsheet with the annually capital cost forecast
Benchmark Data		
	Energy Prices	2015 and 2016 Hourly Energy Price Spreadsheet
	Generator by Fuel Type	Hourly Net Energy Generation Spreadsheet by Fuel Type, in GWh
	Capacity by Fuel Type	Annual Capacity Spreadsheet by Fuel Type, in MW
	Interface Flow/Limits	Hourly Interface Flow and Limit Spreadsheet, in MW
	Total Energy Market	Annual dollar value of day-ahead market including imports/exports, excluding bilateral but separately quantified
	Ancillary Services	Hourly price for reserve prices / regulation prices

Table 9-1: Sample Simulation Model Input Data

10 Appendix V: Some Alberta Electricity Market Data

Alberta Electricity System Overview

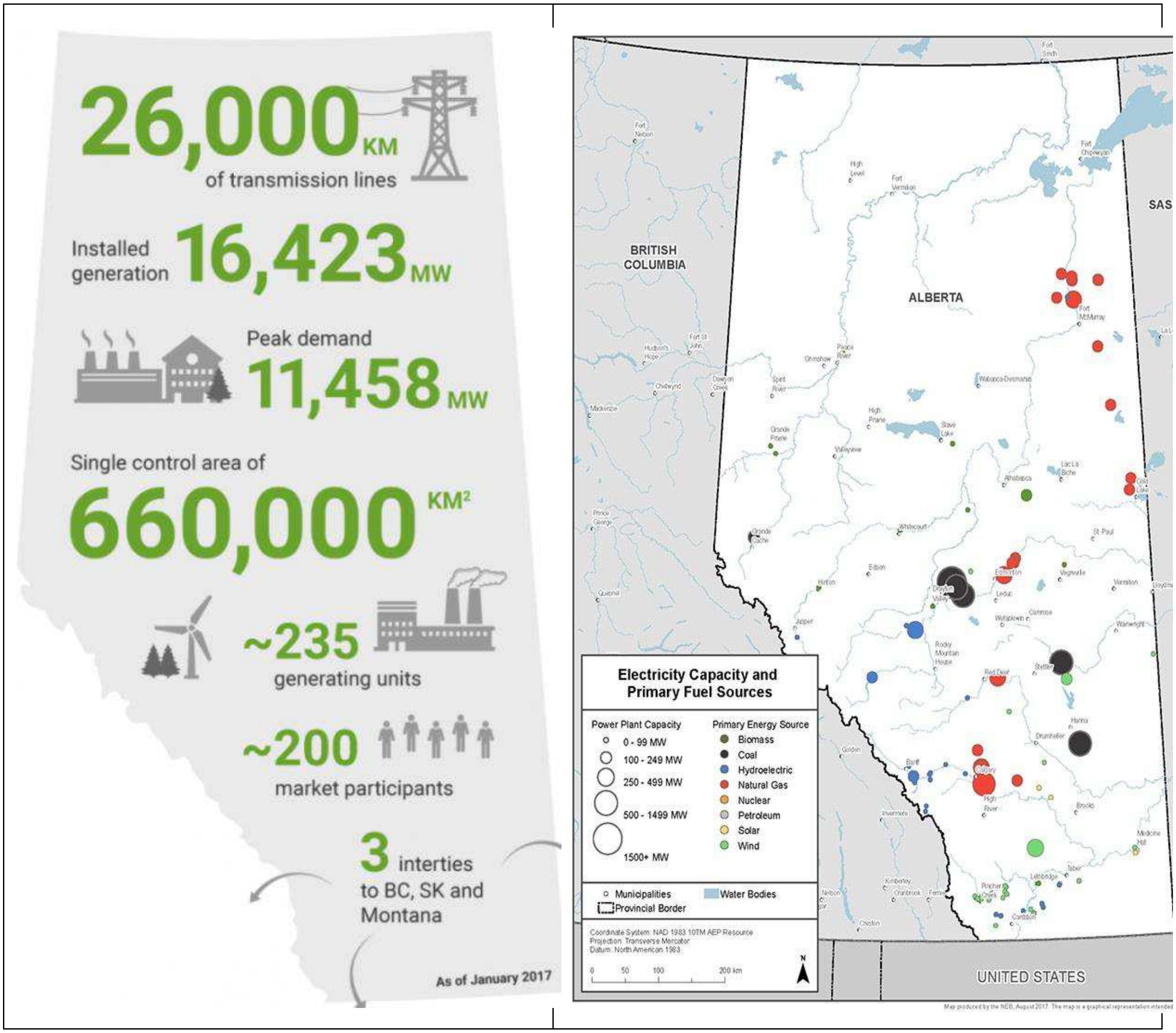


Figure 10-1: Alberta Electricity System Overview (As of January 2017) and Generation Capacity by Primary Fuel Sources

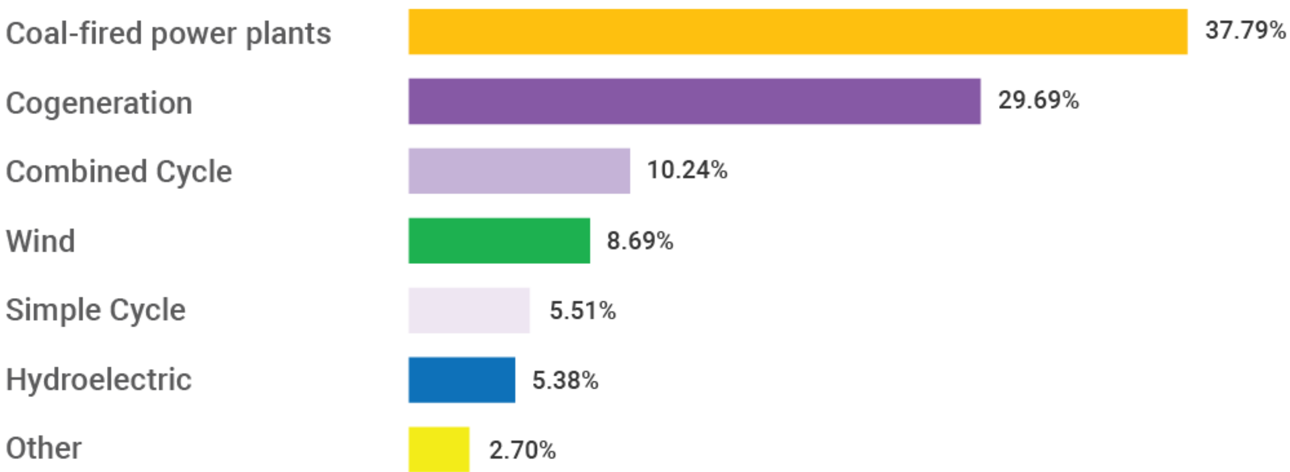


Figure 10-2: Alberta's Electricity Generation Fuels (as of March 2018)

Figure 10-3: Coal Units in Alberta and their Operators

11 Appendix VI: Examples of Energy Storage Benefits (Battery)

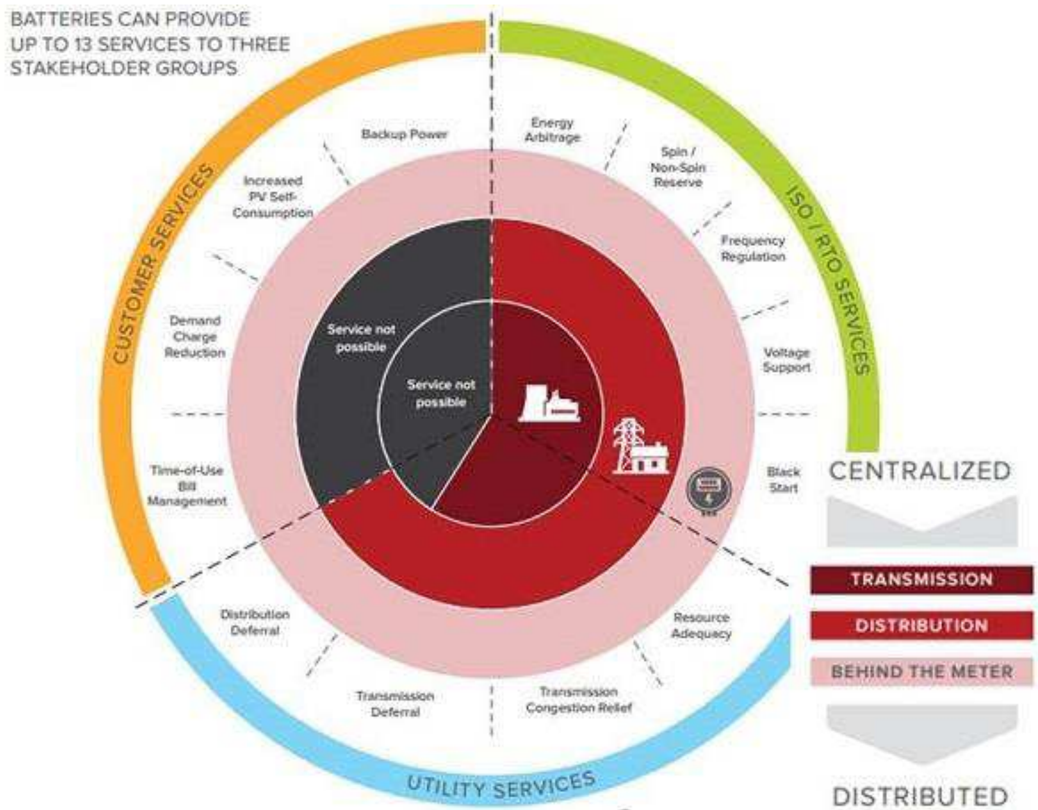


Table 11-1: Example of Benefits Provided by Battery Energy Storage to Various Stakeholders140

140 Rocky Mountain Institute (https://rmi.org/insights/reports/economics-battery-energy-storage/)

12 Appendix VII: Treatment of ES Technology Options

There are several ES technology types in the form of heat or electricity. Within the scope of this project the primary focus has been on Electricity to Electricity (E2E) ES, which can be further broken down into:

- Electrochemical (battery, flow battery…)
- Electromechanical (flywheel, compressed air ES, pumped hydro…)
- Electrical (superconducting electromagnetic ES, capacitors…)

Of these three types of E2E, electrochemical and electromechanical were chosen based on available input data and on AB Stakeholder feedback. The table below shows examples of which electrochemical and electromechanical ES technologies could be studied. The broad power to duration categories from Table 1-2 in section 1 are shown here. They include long duration of 4Hrs or greater (L), medium long duration of 2Hrs (ML), medium short duration of 1Hr (MS), and short duration of 0.5Hr (S). The corresponding color coded bars are indicating ES technologies that tend to be L, S, or some combination thereof (Mass Department of Energy Resources, Mass Clean Energy Center 2016). The dash ('-') indicates that the ES technology doesn't tend to be in that duration category. In summary, these categories are useful for the system level analysis shown in section 1. In section 2 however, it is more practical to state the actual power to duration or respective maximum MW and Hrs of an individual ES technology.

Table 12-1: Examples of Electrochemical and Mechanical ES Technologies

	Electrochemical								Electromechanical			
	Battery					Flow Cell						
PWR:Dur	SuperCap	AdvPbAcid	Li ion	NaS	…	V Red	ZnBr	…	CAES	P-Hydro	Flywheel	…
L	-	-									-	
ML	-										-	
MS	-			-		-	-		-	-	-	
S		-		-		-	-		-	-		

SuperCap: Super Capacitor or Ultra Capacitor
AdvPbAcid: Advanced Lead Acid
Li-ion: Lithium Ion
NaS: Sodium Sulphur
V Red: Vanadium Redox
ZnBr: Zinc Bromide
CAES: Compressed Air Energy Storage
P-Hydro: Pumped Hydro Electric

For the sake of comparison, a conventional technology like CT was also simulated. Taking into account AB stakeholder feedback, the following three ES technologies were chosen:

- Lithium Ion Battery (Li-ion)
- Compressed Air Energy Storage (CAES)
- Pumped Hydro (P-Hydro)

Given AESO's requirement for participation in ancillary markets, the minimum ES capacity rating was assumed at 5MW. The four Power and Duration categories align best with battery technologies with capacities under 1MW. However, these Power and Duration categories may not fit as well to non-battery ES technologies, particularly for capacities greater than or equal to 5MW. The capacities of ES technologies studied in section 2 are all equal to or greater than 10MW and include non-battery ES technologies. The Power and Duration listed here may not necessarily fall into the four categories listed in section 1.

Table 12-2: Power (MW) and Duration (Hr) of ES Technologies and Baseline CT Studied

CT	Energy Storage		
	Electrochemical	Mechanical	
	Battery		
Peaker (20 yrs)	Li-ion (15 yrs)	CAES (40 yrs)	P-Hydro (60 yrs)
50MW	10MW:2Hr	183MW:8Hr	280MW:8Hr
n/a	10MW:4Hr	183MW:26Hr	900MW:16Hr

Cost and performance input data corresponding to ES technologies are displayed above. ES technology and cost and performance data used in ESVT 4.0 were custom inputs based on commercial vendor data supplied to the U.S. DOE in Appendix B of the peer reviewed public report SAND2015-1002 from February 2015 (Akhil, Huff and Currier 2015). It should be noted that the other ES technologies listed in Appendix B, or any commercial at-scale ES cost and performance data, can be used as custom inputs for ESVT 4.0.

Table 12-3: Sources from SAND2015-1002 for ES Technology Cost and Performance Data Listed in Table 11-2 (Akhil, Huff and Currier 2015)

CT	Energy Storage		
	Electrochemical	Mechanical	
	Battery		
Peaker	Li-ion	CAES	P-Hydro
Page, Column	Page, Column	Page, Column	Page, Column
B-21[i]	B-46, S6	B-30, S12	B-27[i]
n/a	B-46, S6[ii]	B-30, S12	B-27

i. Preloaded data from ESVT 4.0 was also used (Electric Power Research Institute 2014)
ii. 10MW 2Hr data was modified to 10MW 4Hr (Lazard 2016)

Both CT and CAES consume natural gas (NG), so TEA calculations in this section assume the same NG prices as previously assumed in section 1. These are 2017 monthly natural gas prices in CAD/MMBtu based on NGX 2015 and 2016 historical data (NGX 2018). Calculated from 2017 to 2030 inclusive, AESO 2017 LTO gas prices are forecasted from 2018 to 2040 (Alberta Electric System Operator 2017) at a fuel escalation rate of 1.727%. If an ES technology requires replacement or rebuild during the study period or technology lifetime, those costs were included as well. For instance, a Li-ion stack lifetime is assumed to be ten years, and thus the simulation takes into account both the cost decline over ten years and the stack replacement costs assumed at year ten (Lazard 2016). Detailed tables for cost, performance and lifetime data are available upon request.

13 Appendix VIII: Resulting Scenarios for Energy Storage Valuation

Given the ES technologies and grid service (GS) use cases presented in Section 2, there are twenty-two resulting scenarios. ES is separated into three ES technologies (Li-ion, CAES, P-Hydro), and further separated into two Li-ion, two CAES and two P-Hydro Power and Duration categories, as well as one CT for a total of seven. GS are separated into two use cases, repeated only for CAES and P-Hydro ES in a sub scenario for transmission deferral. Thus seven technologies in two use cases make fourteen simulations, plus four technologies in two sub scenarios for another eight simulations for a total of twenty two simulations. The format for these possible use case simulations and resulting output is shown in Table 13-1.

Table 13-1: TEA Scenarios and Output Format for Twenty-two TEA Use Case Simulations

	CT	Energy Storage					
GS Bundle	Peaker (MW:Hr)	Li-ion (MW:Hr)		CAES (MW:Hr)		P-Hydro (MW:Hr)	
	50:n/a	10:2	10:4	183:8	183:26	280:8	900:16
1							
2							
1 TD	n/a	n/a	n/a				
2 TD	n/a	n/a	n/a				

Neither CT nor Li-ion could provide Transmission Deferral as the CT technically cannot provide this, and the Li-ion ES capacity rating studied is too small. Hence these scenarios are marked as 'n/a'. Notes:

- Li-ion technologies are not eligible for Black Start Ancillary Services (AESO, Energy Market and Ancillary Services Discussion 2017)
- Both Li-ion 10MW 2Hr and 4Hr cannot provide transmission deferral for the average line studied
- CT cannot provide Transmission Deferral

Of the multiple financial, technical and market results, financial results are shown first. Project NPV follows the format described previously. NPV is then broken into Present Value costs plus benefits, system capacity in MW and, where applicable, system duration in MWHr. These result output formats are shown in Table 13-2. The goal is to use three different ways to compare and rank twenty two TEA simulation results for the different CT and ES technologies as well as their power and duration categories:

a. Cost to benefit ratio over technology lifetime at given power and duration
    - Less than one is a loss, equal to one is break even, and greater than one is a profit
b. 14 year present value least cost: per MW and per MWh
    - The lower the cost the better
c. 14 year max NPV: per MW and per MWh
    - The higher the NPV the better

For each of the twenty two simulations, multiple detailed outputs are also available, including but not limited to:

- NPV Stackable Cost and Benefits
- Annual Service Revenue
- Daily Revenue
- Daily Dispatch

- Detailed Pro Forma

TEA simulation results are shown in three different ways (again marked a, b, and c) so that comparisons could be made among CT and ES technologies with different lifetimes, capacities, and durations. The first way (a) includes both the different capacity and duration ratings as well as the different technology lifetimes as is. The second (b) and third (c) normalize, or take into account, the different capacity and duration ratings as well as the different technology lifetimes. The normalized second way (b) does so from the “least cost provider” perspective and is separated into capacity (power) and then capacity multiplied by duration (energy). The normalized third way (c) considers revenue streams from multiple stackable benefits or market services and is also separated into capacity and then capacity and duration. The CT does not have a duration rating like ES, hence MWh results are marked as ‘n/a’.

Table 13-2: TEA Simulation Outputs by (a) Cost Benefit, (b) Least Cost per MW and MWh, and (c) Maximum NPV per MW and MWh

GS Bundle	CT	Energy Storage					
	Peaker (MW:Hr)	Li-ion (MW:Hr)		CAES (MW:Hr)		P-Hydro (MW:Hr)	
	50:n/a	10:2	10:4	183:8	183:26	280:8	900:16
(a) Cost Benefit Ratio							
1							
2							
1 TD	n/a	n/a	n/a				
2 TD	n/a	n/a	n/a				
(b) 14 yr Least Cost per MW							
1							
2							
1 TD	n/a	n/a	n/a				
2 TD	n/a	n/a	n/a				
(b) 14 yr Least Cost per MWh							
1	n/a						
2	n/a						
1 TD	n/a	n/a	n/a				
2 TD	n/a	n/a	n/a				
(c) 14 yr Maximum NPV per MW							
1							
2							
1 TD	n/a	n/a	n/a				
2 TD	n/a	n/a	n/a				
(c) 14 yr Maximum NPV per MWh							
1	n/a						
2	n/a						
1 TD	n/a	n/a	n/a				
2 TD	n/a	n/a	n/a				

The first set of outputs (a) shows cost benefit ratios over the technology lifetime, or for the total number of years that the technology is operational (20 years for CT, 15 years for Battery ES, 40 years for CAES, and 60 years for Pumped Hydro). Cost benefit ratio (a) is similar to the third approach (c) using NPV, with the exception that the study period, technology lifetime, capacity, and duration are not taken into account or normalized in (a).

The second set of outputs (b) shows the least cost provider approach. This is to align with how a grid operator or utility might evaluate a potential asset. The technology lifetime, capacity and duration are now taken into account using normalization. Here the present value of total project costs is adjusted for the fourteen year study described in the simplified word equations below:

- (Fourteen years/technology lifetime years)*(PV total cost in $M/Capacity of technology in MW)
- (Fourteen years/technology lifetime years)*(PV total cost in $M/Capacity and duration of technology in MWh)

The third set of outputs (c) uses maximum net present value (NPV) and takes not only the total cost in (b) into account, but also benefits or multiple stackable revenue streams from market services that are possible in a de-regulated market. Again this is normalized or adjusted for the fourteen year study, different capacities, and durations as described in the simplified word equations below:

- (Fourteen years/technology lifetime years)*(NPV in $M/Capacity of technology in MW)
- (Fourteen years/technology lifetime years)*(NPV in $M/Capacity and duration of technology in MWh)

Finally, the three main output formats are shown graphically to visualize and contrast which technologies are worth investigating further. This screening and down selection brings to light potential technologies and benefits an operator or owner may otherwise be unaware of. The more thorough analysis on “screened in” technologies can be unpacked into detailed technical, regulatory and financial results via the multiple outputs (NPV stackable cost and benefits, etc.) listed above to make apples to apples comparisons among each other and to the CT.

14 Appendix IX: Annual Services Revenue for Li-ion 10MW 2Hr and 4Hr in Use Case 2

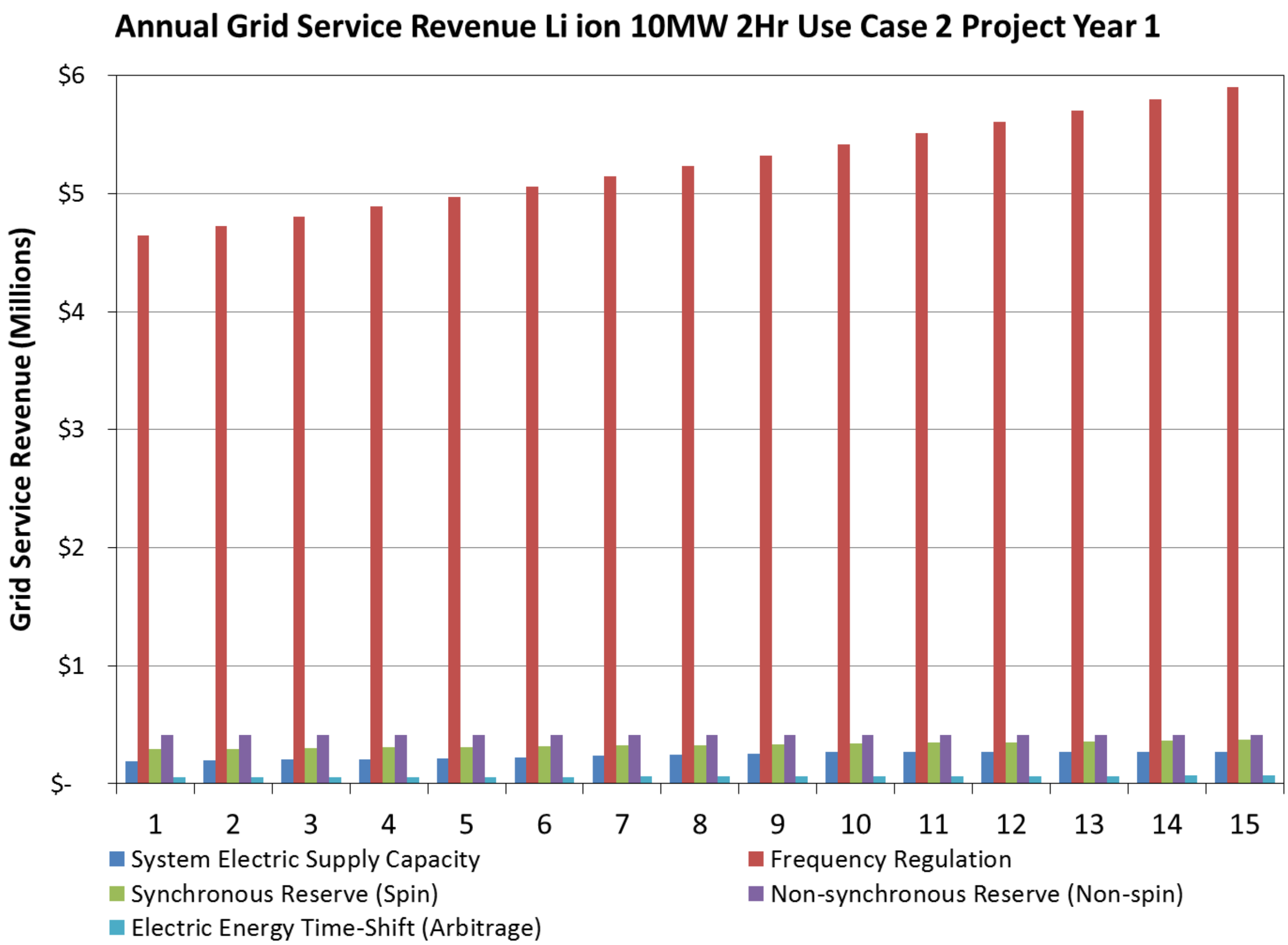


Figure 14-1: 10MW 2Hr Li-ion for GS 2 with NRC's Estimate of a Future AB Capacity Market

Figure 14-1 shows annual service revenues for 10MW 2Hr Li-ion while Figure 14-2 shows the same for 10MW 4Hr Li-ion, both with NRC's estimate of the 2021 Capacity Market (no longer being planned). The comparison is to see the effect of increased duration on Grid Service revenue, particularly for the estimated Capacity Market. The largest revenues or benefits are for Operating Reserves, then Supply Capacity or the estimated Capacity Market, and lastly, Arbitrage or the Energy Market.

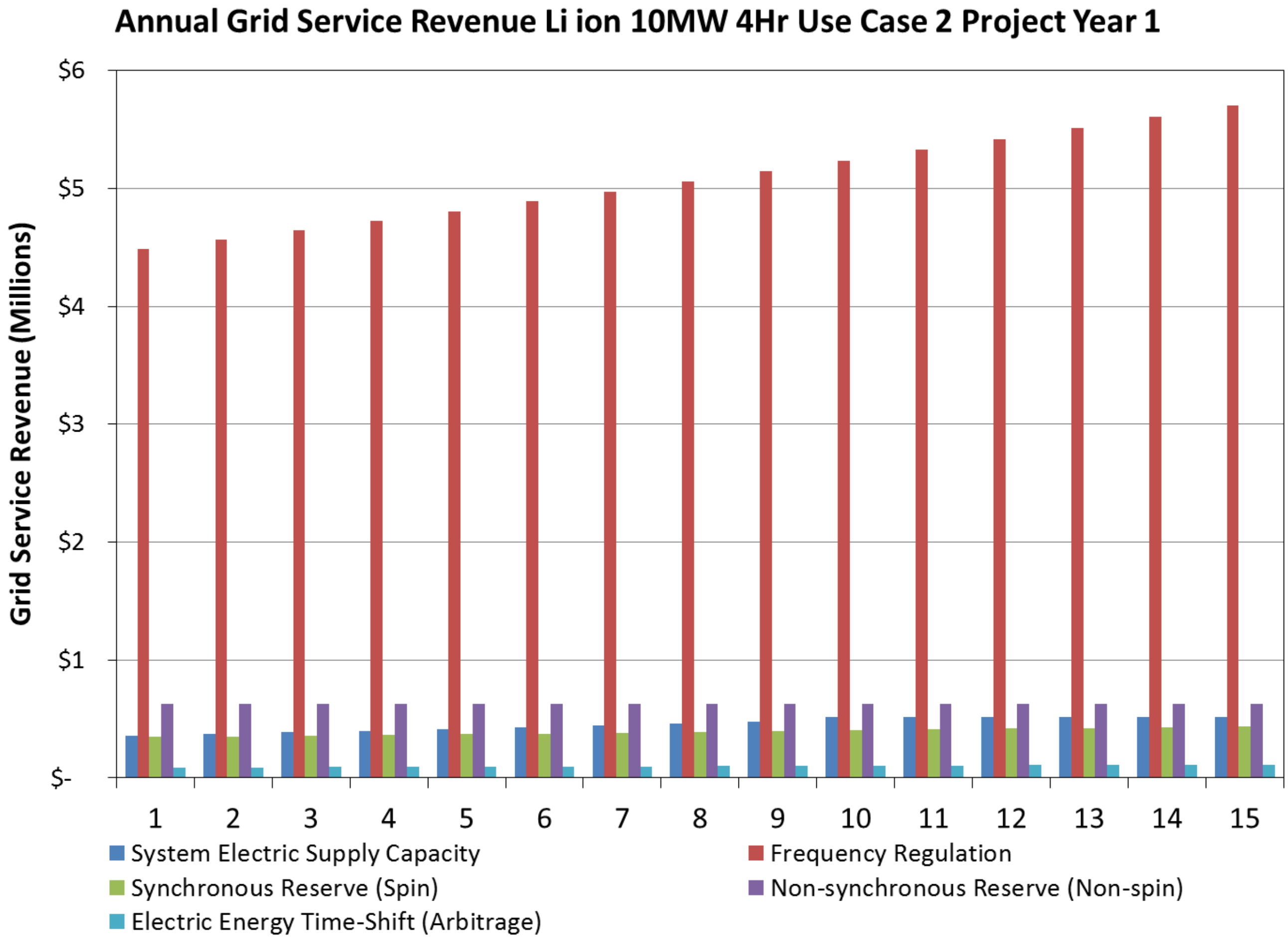


Figure 14-2: 10MW 2Hr Li-ion for GS 2 with NRC's Estimate of a Future AB Capacity Market

Relative to the 10MW 2Hr Li-ion battery, revenues from longer duration Grid Services such as Operating Reserves Contingency Supplemental, NRC's estimate of the 2021 Capacity Market (no longer being planned), and the Energy Market, all increase while the other two Operating Reserves decrease. Therefore, the battery can participate in the estimated Capacity Market as 10MW 4Hr instead of 5MW 4Hr, which almost doubles its revenues from $3.6M to $6.8M (future values) for that Grid Service or Use Case. However, the same situation arises where the increase in capital costs and interest paid on said costs is not outweighed by the corresponding increase in revenues because long duration Grid Services or Use Cases such as the estimated Capacity Market are not as lucrative as short duration ones such as Operating Reserves.

15 Appendix X: Transmission Deferral Sub Scenario for CAES 183MW 8Hr and 26Hr in Use Case 2

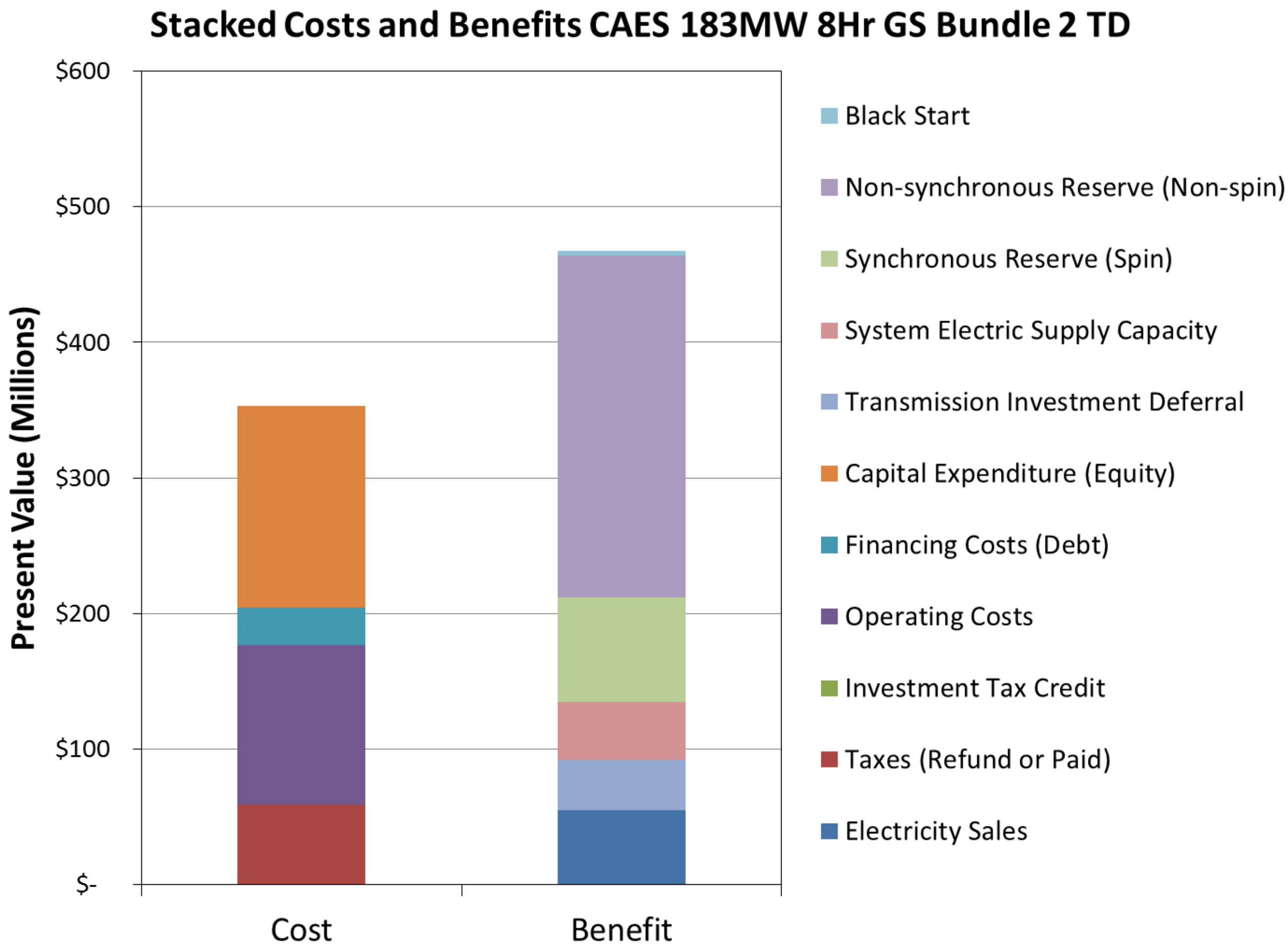


Figure 15-1: Costs and Benefits CAES 183MW 8Hr Stacked for GS 2 with NRC's Estimate of a Future Capacity Market and Transmission Deferral Sub Scenario

The current regulatory framework in Alberta doesn't allow a transmission deferral asset to both sell electricity in the Energy Market and be a regulated transmission asset. This sub scenario shows what's possible if future regulatory changes are made. Stacked costs and benefits are shown in Figure 15-1 and Table 15-1. Both CAES 183MW technologies are shown again, this time with the added Transmission Deferral sub scenario. This not only allows for comparisons between the 8Hr and 26Hr CAES technologies, but also with and without Transmission Deferral. For the 8Hr CAES, the pattern in benefits is the same: Non-synchronous Reserve or OR, Contingency: Supplemental is the largest benefit. What is interesting is Transmission Deferral increases it's benefit at the expense of others, particularly Operating Reserves Supplemental. Hence, by making Transmission Deferral a priority for the ES technology according to a genetic FERC dispatch order, it is providing that benefit over more lucrative ones. Specifically, Transmission Deferral provides a $37.3M benefit while reducing all other benefits by $91.9M for a net decrease in benefits of $54.5M.

Table 15-1: CAES 183MW 8Hr Costs and Benefits for GS 2 with NRC's Estimate of a Future Capacity Market and Transmission Deferral Sub Scenario

	Cost	Benefit	% Cost	% Benefit
Electricity Sales	$ -	$54,662,206	0%	12%
Taxes (Refund or Paid)	$59,264,390	$ -	17%	0%
Operating Costs	$117,573,828	$ -	33%	0%
Financing Costs (Debt)	$27,259,075	$ -	8%	0%
Capital Expenditure (Equity)	$148,908,276	$ -	42%	0%
Transmission Investment Deferral	$ -	$37,325,580	0%	8%
System Electric Supply Capacity	$ -	$42,925,476	0%	9%
Synchronous Reserve (Spin)	$ -	$76,905,519	0%	16%
Non-synchronous Reserve (Non-spin)	$ -	$252,287,289	0%	54%
Black Start	$ -	$3,332,853	0%	1%
Total	$353,005,569	$467,438,925	100%	100%

Regarding costs, the pattern for 8Hr CAES was again the same for Transmission Deferral as it was without. Equity and Operating Costs are by far the largest. The difference in total costs was $32.3M lower for the Transmission Deferral sub scenario. Because CAES was providing Transmission Deferral in place of other benefits like OR, the Operating Costs decreased by $24.8M. Combining the changes in Costs and Benefits for the Transmission Deferral sub scenario, total costs decreased by $32.3M, and total benefits decreased by $54.5M, which reduced the NPV by $22.2M. Thus CAES can provide Transmission Deferral, but in so doing, it decreases it's NPV given Alberta's Markets and Services.

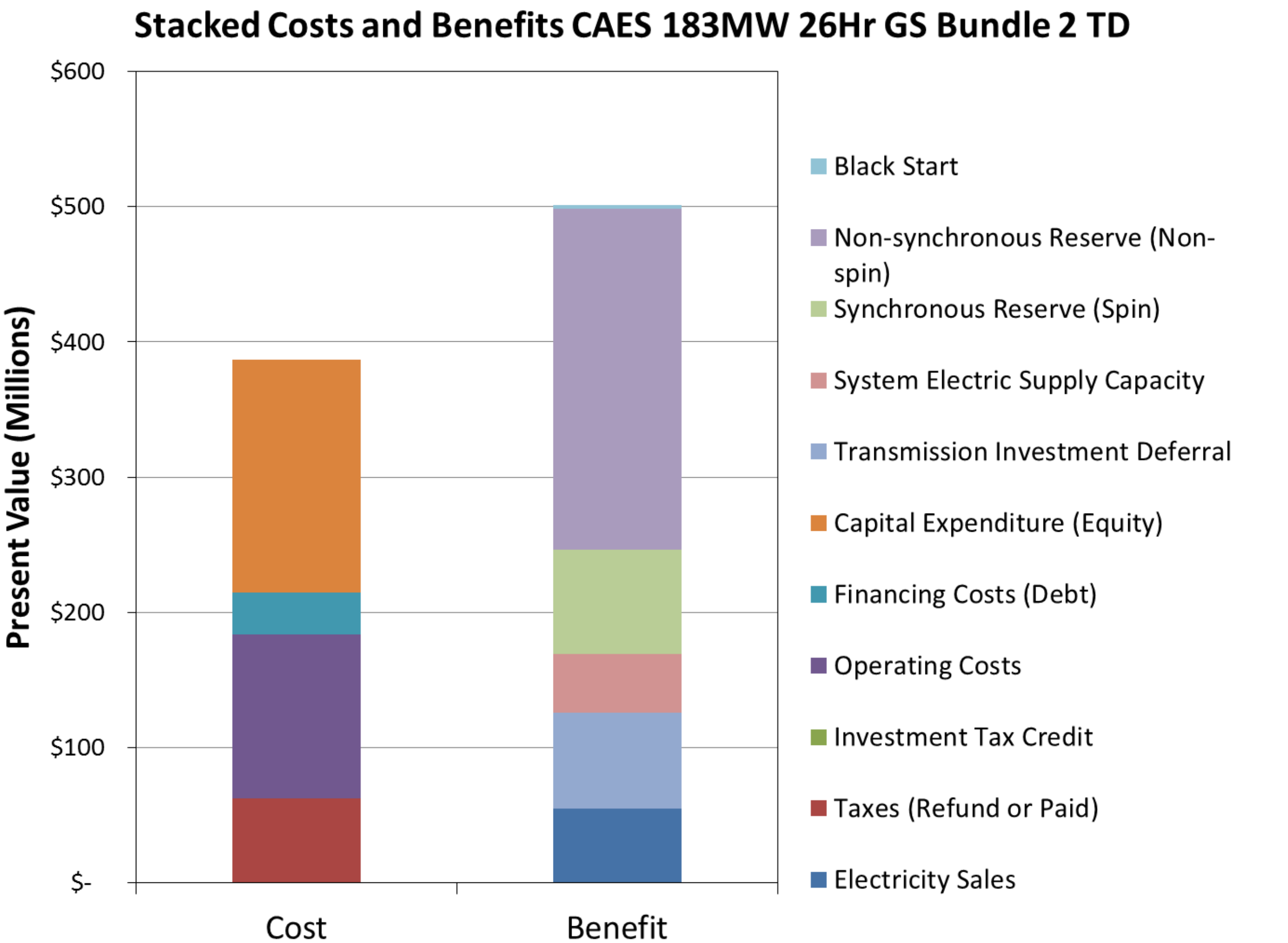


Figure 15-2: CAES 183MW 26Hr Stacked Costs and Benefits for GS 2 with NRC's Estimate of a Future Capacity Market and Transmission Deferral Sub Scenario

Present value stacked costs and benefits for the 26Hr CAES with Transmission Deferral are shown in Figure 15-2 and Table 15-2. The idea is to first compare to 26Hr CAES without Transmission Deferral, and then to 8Hr CAES with Transmission Deferral. The first comparison, to 26Hr CAES without Transmission Deferral sees the same trend as for 8Hr CAES with and without Transmission Deferral. The $71M benefit for Transmission Deferral came at the expense of other more lucrative Markets and Services such as OR. Total benefits decreased by $21.2M from $522.7M to $501.5M. The second comparison, to 8Hr CAES with Transmission Deferral, benefitted with an increase from $37.3M to $71M. The increased duration for 26Hr CAES provided more Transmission Deferral benefits, but not enough to compensate for the decrease in other, more lucrative, benefits.

Table 15-2: CAES 183MW 26Hr Costs and Benefits for GS 2 with NRC's Estimate of a future Capacity Market and Transmission Deferral Sub Scenario

	Cost	Benefit	% Cost	% Benefit
Electricity Sales	$ -	$54,722,193	0%	11%
Taxes (Refund or Paid)	$62,500,311	$ -	16%	0%
Operating Costs	$120,869,883	$ -	31%	0%
Financing Costs (Debt)	$31,514,958	$ -	8%	0%
Capital Expenditure (Equity)	$172,156,907	$ -	44%	0%
Transmission Investment Deferral	$ -	$71,012,927	0%	14%
System Electric Supply Capacity	$ -	$43,618,487	0%	9%
Synchronous Reserve (Spin)	$ -	$77,291,660	0%	15%
Non-synchronous Reserve (Non-spin)	$ -	$251,507,463	0%	50%
Black Start	$ -	$3,332,853	0%	1%
Total	$387,042,058	$501,485,583	100%	100%

With regard to costs, the pattern for 26Hr CAES was again the same for Transmission Deferral as it was without. Equity and Operating Costs are still the largest. The difference in total costs was $24M lower for the Transmission Deferral sub scenario. Because CAES was providing Transmission Deferral in place of other benefits, the Operating Costs decreased by $24.8M, the same as that for 8Hr CAES with Transmission Deferral. Combining the changes in Costs and Benefits for the Transmission Deferral sub scenario, total costs decreased by $24M while total benefits decreased by only $21.2M, which increased NPV by $2.7M compared to 26Hr CAES without Transmission Deferral. This is the opposite of the 8Hr CAES with and without Transmission Deferral.

In summary, the Transmission Deferral sub scenario highlights the opportunity cost of providing long duration grid services over shorter ones. Although the added duration increased NPV for 26Hr CAES when providing Transmission Deferral, compared to 8Hr CAES, the NPV was still lower. Thus 8Hr CAES provides a higher NPV than 26Hr CAES, even though the latter shows a specific application such as Transmission Deferral is both operationally possible and more profitable than without.

16 Appendix XI: Summary of Alberta's Climate Change Framework

Alberta's Climate Change Acts and Regulations	***Key Policy Documents***	***Emissions Reduction Targets***	***Mandatory GHG Requirements***	***Carbon Pricing Mechanism***
- Climate Change and Emissions Management Act (2003) - Specified Gas Reporting Regulation (SGRR) (2004) - Climate Change Leadership Implementation Act (2016) - Oil Sands Emissions Limit Act (2016) - Carbon Competitiveness Incentive Regulation (CCIR) (2018) (Replaces Specified Gas Emitters Regulation (SGR) - 2007)	- Alberta's 2008 Climate Change Strategy. - Climate Leadership Plan (released on November 2015). Plan's four pillars: (i) incentives for renewable generation, (ii) the phase-out of coal-fired power generation by 2030, (iii) the implementation of an economy-wide carbon price, and (iv) the implementation of an energy efficiency program.	- No specified emission reduction targets under the new Climate Leadership Plan; however, the oil sands sector will face a cap of 100,000 Mt in any year with the potential to increase by 10,000 Mt in some circumstances. - Under the 2008 Climate Change Strategy, the following targets were set: - 2020: 50 Mt reduction to stabilize GHG emissions - 2050: 200 Mt reduction to achieve 50% below business as usual and 14% below 2005 levels.	- Any facility regulated under CCIR must submit compliance reports annually, due on March 31 of the following compliance year. Facilities emitting greater than 1,000,000 tonnes CO2e per year must submit compliance reports with true-up quarterly, and provide annual forecasting of emissions, production, and credit usage, with a final annual true-up due on March 31 of the following year. - TIER System: It is proposed that all regulated facilities submit compliance reports annually, due on March 31 of the following compliance year. Facilities would no longer be required to submit quarterly compliance reports and true-up. Facilities emitting greater than 1,000,000 tonnes CO2e per year would be required to submit non-binding annual forecasting reporting.	- Carbon levy is applied to transportation and heating fuels that emit GHG when combusted. Starting on January 1, 2017 the levy rate was introduced at a rate of $20 per tonne of CO2e and has been increased to $30 per tonne since January 1, 2018. - Regulated entities under the CCIR may contribute to the Climate Change and Emissions Management Fund and obtain a fund credit (one tonne of CO_2e). The Alberta's Government has set up the credit amount of money that a facility must contribute to get a fund credit as $30 per tonne for the year 2018 or a subsequent year.

Table 16-1: Summary of Alberta's Climate Change Framework (Alberta 2017b, Canada 2017, Lee-Andersen 2017)

17 Appendix XII: Summary of Life Cycle Inventory – Li-ion Battery and CAES

	Sub-assemblies	Quantity	Unit
Positive electrode paste	Lithium hydroxide (LiOH)	0.4	kg
	Phosphoric acid (H3PO4)	0.6	kg
	Iron Sulphate (FeSO4)	0.9	kg
	Deionized water	40.0	kg
	Carbon black	0.1	kg
	Poly tetra fluoroethylene (PTFE)	0.1	kg
	N-methyl-2-pyrrolidone (NMP)	0.3	kg
Negative electrode paste	Graphite	1.0	kg
	Poly tetra fluoroethylene (PTFE)	0.1	kg
	Nmethyl2pyrrolidone (NMP)	0.3	kg
Separator	Polyethylene, LDPE granulate	0.5	kg
	Polypropylene, granulate	0.5	kg
Substrate, positive electrode	Positive electrode:Sheet rolling, Aluminium	1.0	kg
	Positive electrode: Aluminium, production mix	1.0	kg
Substrate, negative electrode	Negative electrode:Sheet rolling, copper	1.0	kg
	Negative electrode: Copper, primary	1.0	kg
Electrolyte	Chemicals, inorganic [proxy for LiPF6]	0.1	kg
	Chemicals, organic [proxy for solvent]	0.9	kg
Cell container, tab and terminals	Aluminium, production mix	1.0	kg
	Sheet rolling, aluminum	1.0	kg
Module and battery packaging	Polyethylene terephthalate	1.0	kg
	Injection moulding	1.0	kg
Battery management system (BMS)	Integrated circuit, logic type	0.1	kg
	Copper, primary	0.5	kg
	Chromium steel 18/8	0.4	kg
	Wire drawing, copper	0.5	kg
	Sheet rolling, steel	0.4	kg

Table 17-1: Life Cycle Inventory Table for Li-ion Battery Pack System (Majeau-Bettez, Hawkins and Stromman 2011)

	Sub-assemblies	Quantity	Unit
Air compressor system	Hp compressor	1	p
	Lp compressor	1	p
	Lubricating oil	50	L
	Lubricating system	4	p
	Noise isolation	150	m2
	Anti-icing system	2	p
	Control systems	30	kg
Air turbines(s)	Turbine generator	2	p
	Lubricating oil	50	L
	Lubricating system	4	p
	Noise isolation	150	m2
	Control systems	30	kg
Recuperators	Waste heat recuperator	2	p
	Duct system	200	m
	Emission control system elec	400	kg
	Emissions control system pumps	4	p
Circulating system	Water pump	4	p
	Piping	300	m
Cooling system	Cooling tower	1	p
	Pump	2	p
	H_2O pumps	4	p
	Control systems	50	kg
Water treatment	Tank	1	p
	Sumps	4	p
	Pumps	3	p
	Separators	4	p
Fuel system	Metering systems	20	kg
	Regulation systems	80	kg
	Piping	90	m
Transformers	Aux. system transf.	2	p
	Cabling	200	kg
	Generators	6	p
	Ducts	50	m
Power distribution center	Control systems	300	kg
	Piping	150	m
	Ups	400	kg
Emission monitor system	Computers	5	p
	Analyzers, samplers, lines	1,000	kg
Plant control system	Central control	2,000	kg
Building	Building Area	20,000	m2
Storage	Vessels	50	p
	Piping	1000	kg
	Rubber	50	kg

Table 17-2: Life Cycle Inventory Table for CAES System (Oliveira, et al. 2015)

18 Appendix XIII: ES Deployment Scenarios by Technology

Even the annual ES deployment for the benchmark scenario, which is shown in Appendix I, may not suggest that specifically an ES facility will be built at 3 MW or 33 MW each, but rather Pillar 3 analyzed the total annual ES deployment as a whole to be distributed among Li-ion battery and CAES systems. Table 18-1 shows 8 ES allocation scenarios considering combinations of assumed ES capacity distribution for Li-ion and CAES energy storage systems for 2030. Note that Li-ion battery ES systems are deployed in all the suggested deployment years, i.e. 2024, 2027, 2029 and 2030, while CAES systems are deployed only in 2030. The CAES deployment scenarios considered the economics of CAES technologies that suggest a minimum CAES capacity rating of 100 MW.

ESS allocation scenarios	2024 (75 MW)		2027 (28 MW)		2029 (264 MW)		2030 (785 MW)		Total deployment (MW) scenario	
	CAES	Li-Ion	CAES	Li-Ion	CAES	Li-Ion	CAES	Li-Ion	CAES	Li-Ion
1	0	75	0	28	0	264	0	785	0	1152
2	0	75	0	28	0	264	102	683	102	1050
3	0	75	0	28	0	264	196	589	196	956
4	0	75	0	28	0	264	314	471	314	838
5	0	75	0	28	0	264	393	393	393	760
6	0	75	0	28	0	264	471	314	471	681
7	0	75	0	28	0	264	589	196	589	563
8	0	75	0	28	0	264	785	0	785	367

Table 18-1: ES Allocation Scenarios by Technology for the Base Case

Where variations in 2030:
Scenario 1: 100% Li-Ion deployment
Scenario 2: 13% CAES and 87% Li-Ion deployment
Scenario 3: 25% CAES and 75% Li-Ion deployment
Scenario 4: 40% CAES and 60% Li-Ion deployment
Scenario 5: 50% CAES and 50% Li-Ion deployment
Scenario 6: 60% CAES and 40% Li-Ion deployment
Scenario 7: 75% CAES and 25% Li-Ion deployment
Scenario 8: 100% CAES deployment

19 Appendix XIV: ES Environmental Impact at Grid Level for Different ES Deployment Scenarios

Cradle-to-gate emissions generated per type of ES system deployed for each allocated scenario are expressed in absolute values ($MtCO_{2e}$) and calculated by:

(i) Rescaling the cradle-to-gate emissions per energy delivered during complete lifetime utilization expressed in kg CO_{2e}/MWh_d and shown in Table 3-6 to cradle-to-gate emissions per MW deployed expressed in $MtCO_{2e}/MW$.

(ii) Applying the rescaled cradle-to-gate emissions per type of ES technology expressed in $MtCO_{2e}/MW$ (deployed) to the respective annual ES capacity deployment in MW from Table 18-1 for each scenario. Annual cradle-to-gate emissions in absolute values are then added to obtain the total cradle-to-gate emissions per type of ES system for each scenario.

The table below shows the ES environmental impact at grid level for different ES deployment scenarios. Each environmental impact scenario is obtained by adding the overall ES cradle-to-gate emissions from Li-ion battery and CAES systems for each ES deployment scenario and the grid-level GHG emissions reductions from ES usage, i.e. 0.68 Mt of CO_{2e}, as a result of total fossil fuel emissions reductions from ES usage at the grid level. In the scenarios of CAES deployment, the GHG emissions from CAES operation due to natural gas combustion are added to the respective cradle-to-gate emissions calculation.

ESS allocation scenarios	CAES			Li-Ion		GHG emissions from ES manufacturing (Mt CO_{2e})	Grid-level GHG emissions from ES usage ($MtCO_{2e}$)	ES environmental impact at grid level ($MtCO_{2e}$)
	ESS deployment (MW)	GHG emissions (Mt CO_{2e})		ESS deployment (MW)	Cradle-to-gate GHG emissions (Mt CO_{2e})			
		Cradle-to-gate	NG operating					
1	0	0.00	0.00	1152	2.86	2.86	-0.68	2.18
2	102	0.29	0.04	1050	2.61	2.94	-0.68	2.26
3	196	0.56	0.08	956	2.37	3.01	-0.68	2.33
4	314	0.89	0.13	838	2.08	3.10	-0.68	2.42
5	393	1.11	0.16	759	1.89	3.16	-0.68	2.48
6	471	1.34	0.19	681	1.69	3.22	-0.68	2.54
7	589	1.67	0.24	563	1.40	3.31	-0.68	2.63
8	785	2	0.31	367	0.91	3.46	-0.68	2.78

Table 19-1: ES Environmental Impact at Grid Level for Different ES Deployment Scenarios

20 Appendix XV: Estimated Coal-Fired Generation Facilities Offline Schedule

In the study, it is anticipated that all coal-fired generation facilities in Alberta will come offline per the "Anticipated Coal-Fired Generation Facilities Offline Schedule" in the table below, regardless of whether a facility is decommissioned permanently or converted to another form of generation.

Size (MW)	Facility Name	Commissioning Year	End of Useful Life under Current Federal Coal Regulation[141]	Alberta Climate Plan Default[142]	Simulator Suggested Facility Retirement Date[143]
463	Keephills 3	2011	Dec. 31, 2061	2030	TBD
466	Genesee 3	2005	Dec. 31, 2055	2030	TBD
400	Genesee 2	1989	Dec. 31, 2039	2030	Dec-31-2026
400	Genesee 1	1994	Dec. 31, 2044	2030	Dec-31-2028
390	Sherness 2	1990	Dec. 31, 2040	2030	Dec-31-2027
400	Sherness 1	1986	Dec. 31, 2036	2030	Dec-31-2026
395	Keephills 2	1983	Dec. 31, 2029	2030	Dec-31-2024
395	Keephills 1	1983	Dec. 31, 2029	2030	Dec-31-2023
401	Sundance 6	1980	Dec. 31, 2029	2030	Dec-31-2020
406	Sundance 5	1978	Dec. 31, 2028	2028	Dec-31-2020
406	Sundance 4	1977	Dec. 31, 2027	2027	Dec-31-2020
368	Sundance 3	1976	Dec. 31, 2026	2026	Dec-31-2020
385	Battle River 5	1981	Dec. 31, 2029	2030	Dec-31-2021
155	Battle River 4	1975	Dec. 31, 2025	2025	Dec-31-2019
280	Sundance 2	1973	Dec. 31, 2019	2019	Dec-31-2019
280	Sundance 1	1970	Dec. 31, 2019	2019	Dec-31-2019
149	Battle River 3	1969	Dec. 31, 2019	2019	Dec-31-2019
144	HR Milner	1972	Dec. 31, 2019	2019	Dec-31-2019

Table 20-1: Estimated Coal-Fired Generation Facilities Offline Schedule

[141] AESO 2017 Long-term Outlook report (https://www.aeso.ca/grid/forecasting/)

[142] https://www.iisd.org/sites/default/files/publications/alberta-coal-phase-out.pdf

[143] Outputs of simulation for the AB chapter of the Canadian Energy Storage study